Exhibit A

Proposed Reliability Standards Submitted for Approval

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

 4.1. Functional entities

  4.1.1 Generator Owner

  4.1.2 Transmission Owner that owns synchronous condenser(s)

 4.2. Facilities:

 For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

  4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

  4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

  4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

5. **Effective Date:**

 5.1. In those jurisdictions where regulatory approval is required[1]:

  5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

  5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

  5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required[2]:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Note: The verification percentage above is based on the number of applicable units owned.

[2] Wind farm verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Requirements

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units.

3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

B. Measures

M1. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R1.

M2. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, or dated information collected and used to complete attachments and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R2.

M3. Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing 1 to less than or equal to 33 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing more than 33 to 66 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data. OR	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner failed to verify the Real Power capability, per Attachment 1 of an applicable generating unit. OR The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item

	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R2	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the Reactive	The Generator Owner verified and recorded the Reactive Power

	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Generator Owner performed the Reactive Power verification per	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2	Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72	capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR

	Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	(5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	calendar months but less than or equal to 75 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R3	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120	The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is

	than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less	calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.	calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.	recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit. OR The Transmission Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15calendar months.

	than or equal to 69 months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	

D. Regional Variances

None

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06
2	February 7, 2013	Adopted by NERC Board of Trustees	Revised per SAR for Project 2007-09 and combined with MOD-024-1

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months. The first verification for each applicable Facility under this standard must be a staged test.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date. Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 12 calendar months.

It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below.

If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability

verification. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU

transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator, if applicable.

3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature
- Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.

3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.

5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.

Note 1: Under some transmission system conditions, the data points obtained by the Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The Mvar limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

Note 4: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

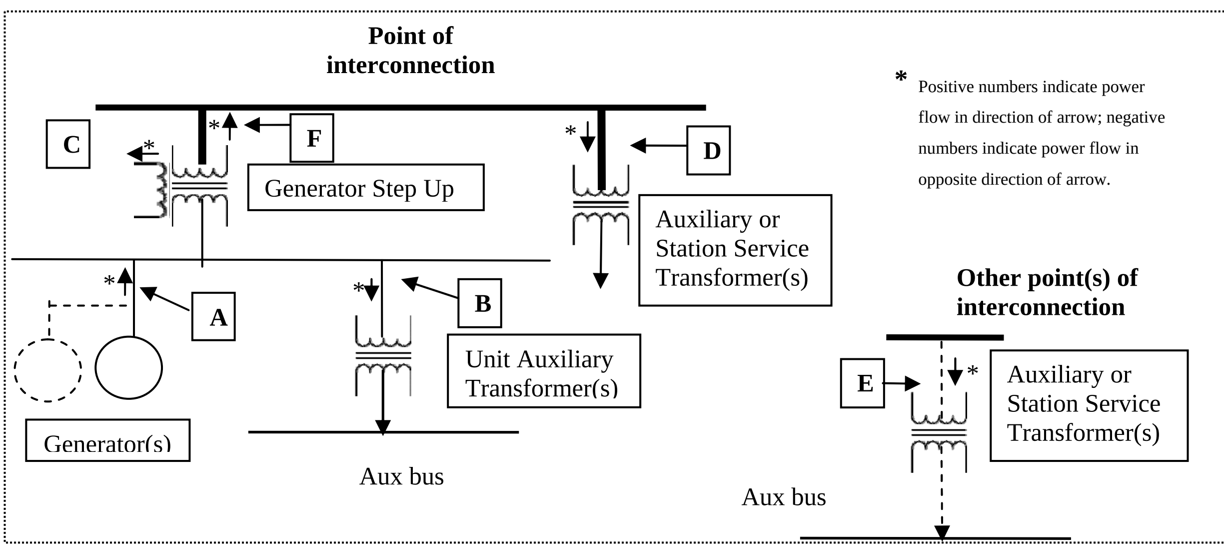
Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

Check all that apply:

- ☐ Over-excited Full Load Reactive Power Verification
- ☐ Under-excited Full Load Reactive Power Verification
- ☐ Over-excited Minimum Load Reactive Power Verification
- ☐ Under-excited Minimum Load Reactive Power Verification
- ☐ Real Power Verification
- ☐ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Reactive Power Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Voltage Ratio: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end of the verification period:

  Air temperature: _________

  Humidity: _________

  Cooling water temperature: _________

  Other data as applicable: _________

- Generator hydrogen pressure at time of test (if applicable) _____________

Date that data shown in last verification column in table above was taken _____________

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the generator excitation control system or plant volt/var control function[1] model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner

   4.1.2 Transmission Planner

   4.2. Facilities:

   For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an "applicable unit" that meet the following:

   4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

   4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

   4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

   4.2.2 Generation in the Western Interconnection with the following characteristics:

   4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

   4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

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[1] Excitation control system or plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation and power system stabilizer.

b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 For all Interconnections:

- A technically justified[2] unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner.

5. Effective Date:

5.1. For Requirements R1, and R3 through R6, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years

[2] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request : *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of excitation control system or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic excitation control system or plant volt/var control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific excitation control system or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification for individual units less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s), or both. Each verification shall include the following:

2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,

2.1.2. Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed),

2.1.3. Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator,

2.1.4. Model structure and data for the excitation control system, including the closed loop voltage regulator if a closed loop voltage regulator is installed or the model structure and data for the plant volt/var control function system,

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used, and

2.1.6. Model structure and data for power system stabilizer, if so equipped.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit:

- Written notification from its Transmission Planner (in accordance with Requirement R6) that the excitation control system or plant volt/var control function model is not usable,
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system or plant volt/var control function model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated excitation control system or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[3] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[4] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the excitation control system or plant volt/var control function that alter the equipment response characteristic.[5] *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

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[3] If verification is performed, the 10-year period as outlined in MOD-026 Attachment 1 is reset.

[4] Ibid

[5] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

R5. Each Generator Owner shall provide a written response to its Transmission Planner, within 90 calendar days following receipt of a technically justified[6] unit request from the Transmission Planner to perform a model review of a unit or plant that includes one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Details of plans to verify the model (in accordance with Requirement R2), or
- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.

R6. Each Transmission Planner shall provide a written response to the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 6.1 through 6.3) or is not usable.

6.1. The excitation control system or plant volt/var control function model initializes to compute modeling data without error,

6.2. A no-disturbance simulation results in negligible transients, and

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator excitation control system or plant volt/var control function model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence

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[6] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 180 calendar days of making changes.

M5. Evidence for Requirement R5 must include the Generator Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 90 calendar days following receipt of a technically justified request.

M6. Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for three calendar years from the date the document was provided.

- The Generator Owner shall retain the latest excitation control system or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner after the timeframe specified in MOD-026 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner verified models that omitted one of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted two of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) but omitted four or more of the six parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice. OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.
R5	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner failed to provide a written response to the Transmission Planner within 180 calendar days following receipt of a technically justified request to perform a model review of an applicable unit. OR The Generator Owner's written response failed to include one of the sub bullets of Requirement R5.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for all specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, “Model Validation for Wind Turbine Generator Models”, IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, “Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, “Dynamic Modeling of GE Wind Plants for Stability Simulations,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, “Description and Technical Specifications for Generic WTG Models – A Status Report,” Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ
9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, “Modeling of GE Wind Turbine-Generators for Grid Studies,” version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, “Field Testing & Model Validation of Wind Plants,” in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, “Experience with Field and Factory Testing for Model Validation of GE Wind Plants,” in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belgium, March/April 2008
13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307

14. W.W. Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, “Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations,” Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003
17. P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 10-year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
5	The Generator Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
6	New or existing applicable unit does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).
7	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10-year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Establishing the recurring 10-year unit verification period start date:

The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 2: Consideration for early compliance:

Existing generator excitation control system or plant volt/var control function model verification is sufficient for demonstrating compliance for a 10-year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

A. Introduction

1. Title: Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

2. Number: MOD-027-1

3. Purpose: To verify that the turbine/governor and load control or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

4. Applicability:

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an "applicable unit" that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

[1] Turbine/governor and load control or active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

5. Effective Date:

5.1. For Requirements R1, and R3 through R5, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of turbine/governor and load control or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) models.

R2. Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both. Each verification shall include the following:

2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response for either:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 Note 1 with the applicable unit on-line,
- A speed governor reference change with the applicable unit on-line, or
- A partial load rejection test,[2]

2.1.2. Type of governor and load control or active power control/frequency control[3] equipment,

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[2] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply.

[3] Turbine/governor and load control or active power/frequency control:

2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer),

2.1.4. Model structure and data for turbine/governor and load control or active power/frequency control, and

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit.

- Written notification, from its Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control or active power/frequency control model is not "usable,"
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[4] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[5] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic[6]. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

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a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

[4] If verification is performed, the 10 year period as outlined in MOD-027 Attachment 1 is reset.

[5] Ibid.

[6] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

R5. Each Transmission Planner shall provide a written response to the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable.

5.1. The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,

5.2. A no-disturbance simulation results in negligible transients, and

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instruction or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 180 calendar days of making changes.

M5. Evidence of Requirement R5 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and for a model that is not useable, a technical description is the model is not usable, and dated evidence of transmittal (e.g., electronic mail messages, postal receipts, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1; OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1; OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice; OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that altered the equipment response characteristic.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information;	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information; OR The Transmission Planner’s written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information; OR The Transmission Planner’s written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information; OR The Transmission Planner provided a written response without including confirmation of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control or active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005
3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004
4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004
5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004
6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003
7) P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 10year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 2).
3	Applicable unit is not subjected to a frequency excursion per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit's real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit's real power response as expected.
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
5	Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location; AND Each applicable unit has the same MVA nameplate rating; AND The nameplate rating is ≤ 350 MVA; AND Each applicable unit has the same components and settings; AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
6	The Generator Owner has submitted a verification plan. (Requirement R3 or R4)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.
8	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10 calendar year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Unit model verification frequency excursion criteria:

- ≥ 0.05 hertz deviation (nadir point) from scheduled frequency for the Eastern Interconnection with the applicable unit operating in a frequency responsive mode
- ≥ 0.10 hertz deviation (nadir point) from scheduled frequency for the ERCOT and Western Interconnections with the applicable unit operating in a frequency responsive mode
- ≥ 0.15 hertz deviation (nadir point) from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode

NOTE 2: Establishing the recurring ten year unit verification period start date:

- The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 3: Consideration for early compliance:

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a 10 year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-1

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each

Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[1] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

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[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar

	years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,”Protective Relaying For Power Generation Systems”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

“Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

“IEEE C37.102-2006 IEEE Guide for AC Generator Protection”

“IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above”

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

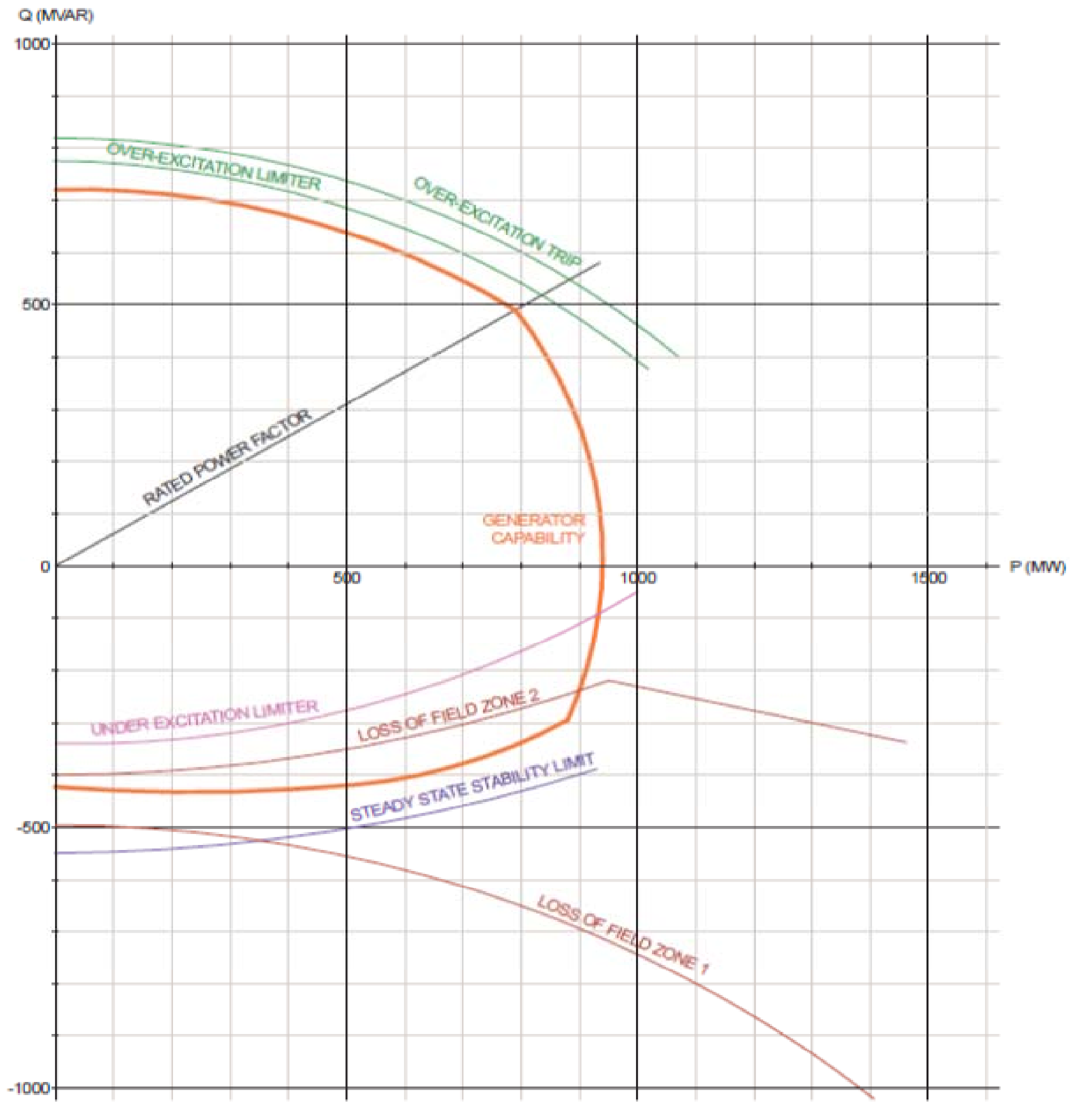
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

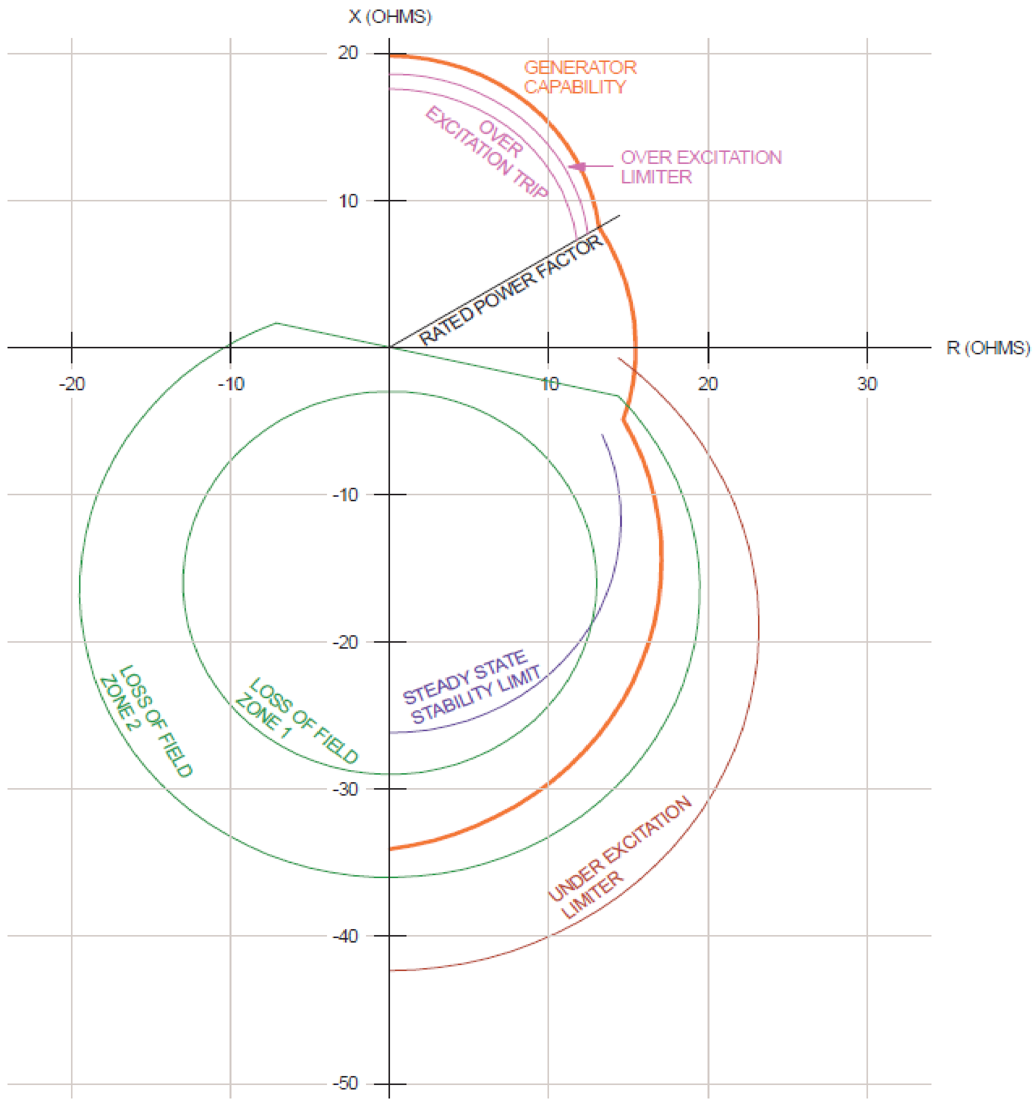
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

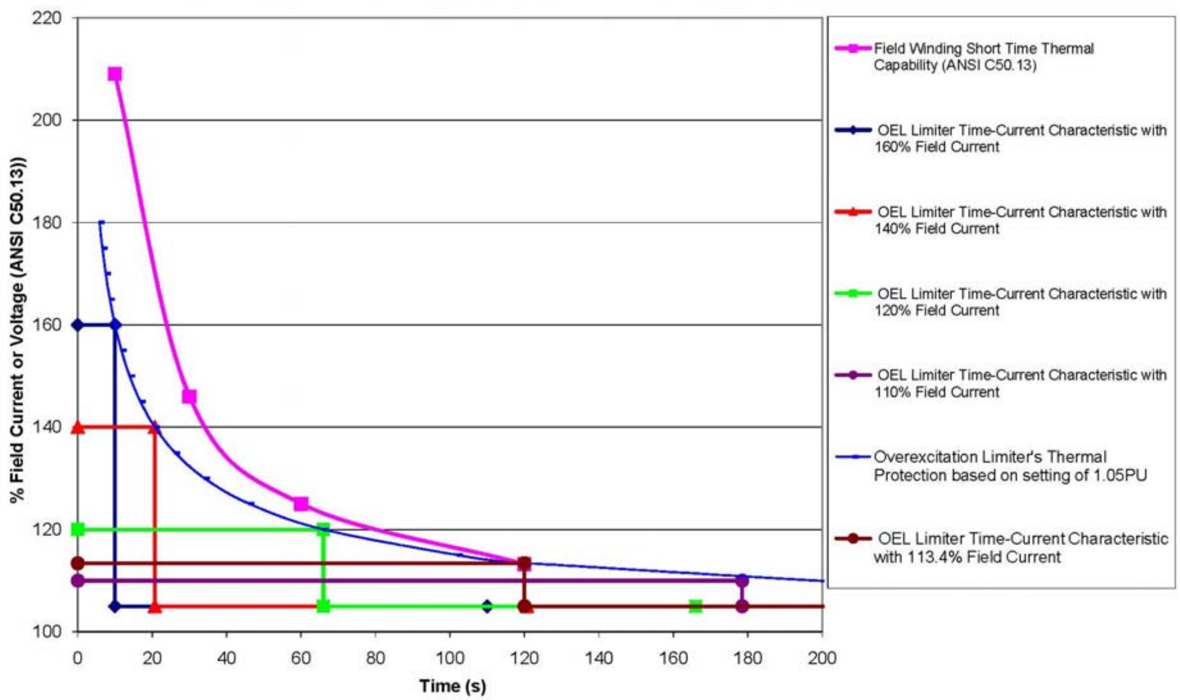
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



A. Introduction

1. Title: Generator Frequency and Voltage Protective Relay Settings

2. Number: **PRC-024-1**

3. Purpose: Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

4. Applicability:

4.1. Generator Owner

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[2]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[3] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement

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[3] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

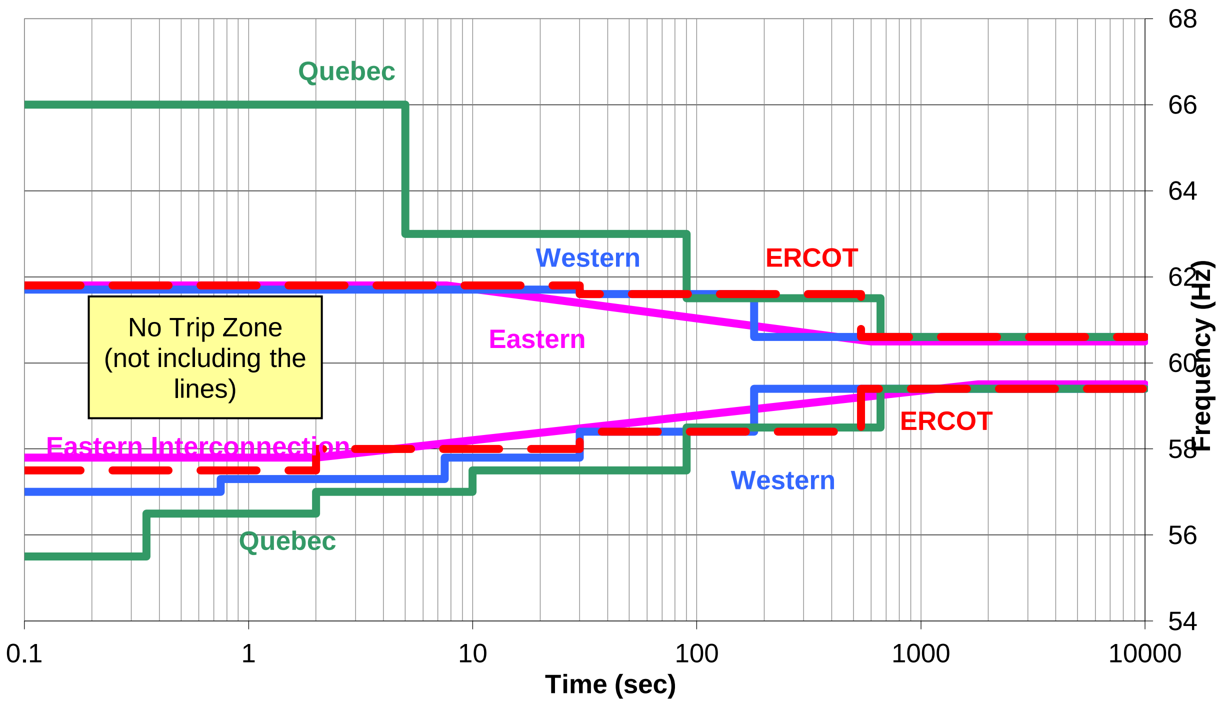
Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

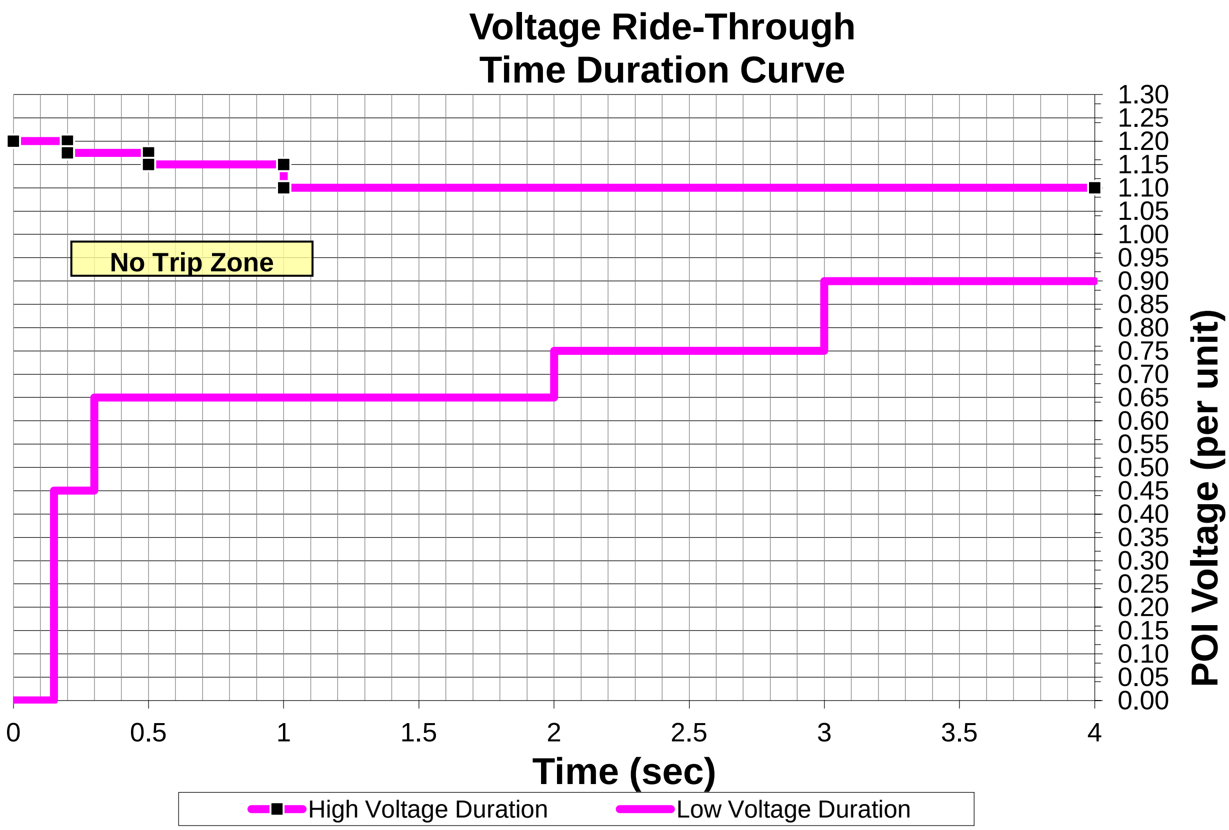
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (Sec)**
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Exhibit B

Implementation Plan for Reliability Standards Submitted for Approval

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Approvals Required

MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Transmission Owner that owns synchronous condenser(s)

Facilities

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO

governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.

- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

In those jurisdictions where regulatory approval is not required:

- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20 percent of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20 percent annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Retirements

MOD-024-1 - Verification of Generator Gross and Net Real Power Capability and MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability should both be retired at midnight of the day immediately prior to the Effective Date of MOD-025-2 in the particular jurisdiction in which the new standard is becoming effective.

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Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units."

Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant / Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

For all Interconnections:

- Any technically justified[1] unit that meets NERC registry criteria and is requested by the Transmission Planner.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA are compliant with Requirement R2 By the first day of the first calendar quarter, 10 years

[1] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA is compliant with Requirement R2 By the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a 10 year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the 10 year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements 10 years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Retirements

None

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Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following Board of Trustees adoption.

- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

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Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Approvals Required

PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner that owns synchronous condenser(s)

Applicable Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any of the following:

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System;
- Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System;
- Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating);
- Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

Conforming Changes to Other Standards
None

Effective Dates
PRC-019-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.
- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Justification for Phasing:

The coordination activities in this standard (PRC-019-1) are most effectively performed just prior to the performance of a reactive capability test, as required by MOD-025-2. Hence, the SDT has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2.

Retirements

None

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Frequency and Voltage Protective Relay Settings

Approvals Required

PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024-1 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to

such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, and R4 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Exhibit C

Order No. 672 Criteria

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The proposed Standards achieve the specific reliability goal of ensuring that (i) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities), and (ii) generator models accurately reflect the generator's capabilities and operating characteristics. Together, these five proposed Reliability Standards address generator verifications needed to support Bulk-Power System reliability and will ensure that accurate data is collected, verified, and made available for planning simulations.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. All of the proposed Reliability Standards apply to Generator Owners. MOD-025-2 and PRC-019-1 also apply to Transmission Owners that own synchronous condenser(s). MOD-026-1 and MOD-027-1 also apply to Transmission Planners.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [5]

The proposed Reliability Standards contain Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help provide clarity regarding how the Requirements will be enforced, and ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve the reliability goal effectively and efficiently in accordance with Order No. 672.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

[5] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standards represent a significant improvement over the previous version as described herein.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed Reliability Standards do not restrict the available transmission capability or limit use of the bulk-power system in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective dates for the Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the standards against the

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[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[10] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. This will allow applicable entities adequate time to ensure compliance with the requirements.

Specifically, the proposed implementation plans for MOD-026-1 and MOD-027-1 are of a longer duration due to the complexity of the tasks involved. Model verification testing on generating units is a relatively specialized and complex task that involves some risk to the operating unit. The reasons for this are as follows:

- The unit must have temporary monitoring equipment connected to record the necessary parameters;
- To install the equipment necessary to obtain shaft position information, a unit shutdown may be required;
- A specialized skill set is required both to perform the test and to process the data obtained during testing. There are not large numbers of these personnel available;
- Each unit takes 2-3 days to instrument, collect data, and then process the data to verify that the model is correct, unlike MOD-025 testing which can typically be accomplished with already installed instruments and within 1 day.

Given that there are many units to test, a long period of time was deemed to be necessary to get all the units complete. Obviously, entities with few units will probably have more time than needed, but entities with large numbers of units may be challenged even by the 10 year period. If the planning entity has a need for a particular unit, they can require that unit to be verified under Requirement R3 of the proposed Standards. The proposed effective dates are explained in the proposed Implementation Plan, attached as **Exhibit C**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

[11] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. **Exhibit E** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standards.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received that indicated the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Analysis of how VRFs and VSLs Were Determined Using Commission Guidelines

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control; or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup Facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and Facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical Facilities
- Appropriate use of transmission Loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4; whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for MOD-025-2:

There are three requirements in MOD-025-2. Each requirement was assigned a "Medium" VRF.

VRF for MOD-025-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each Requirement in MOD-025-1 is assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirements R2 and R3. Each requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC's definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R2:

- FERC Guideline 2 — Consistency within is similar in scope to Requirements R1 and R3. Each Requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept, and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit as specified in this standard.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each requirement in MOD-025-1 is assigned a “Medium” VRF. Requirement R3 is similar in scope to Requirements R1 and R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0, Requirements R1 and R2, in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC’s definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned “Medium” VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R3 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-025-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-025-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms, and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action, and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation, and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-026-1 — Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-026-1:

There are six requirements in MOD-026-1. Four requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-026-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This requirement is administrative in nature for providing instructions and data used for performing model verification. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to provide a written response after receiving a request. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R5 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to

effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-026-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for MOD-026-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is timely. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness with completeness of information required for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R5:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating equal multiple parts criteria VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts also incorporate increments for tardiness consideration. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s are a combination of completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-027-1:

There are five requirements in MOD-027-1. Three requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-027-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This

requirement is administrative in nature for providing instructions and data used for performing model verification. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 which have an approved VRF of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contains Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R6 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-027-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-027-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is timely. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-019-1:

There are two requirements in PRC-019-1 and both have been assigned a "Medium" VRF.

VRF for PRC-019-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R1 is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to periodically verify voltage regulation controls, limiters and protection coordinated with unit

and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 and Part 1.1 have a reliability objective to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-019-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R2 is similar in concept with both PRC-010-0 Requirement R1 and PRC-014-0 Requirement R1, both of which require 5-year verification of protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify coordination following setting changes affecting unit or synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 has a high reliability objective to specify the periodicity for verifying voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination following a change to equipment settings. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal,

or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. . The “Medium” VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-019-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-019-1 Requirement R1:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	The proposed VSLs are based on increments of tardiness for completing the required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider performing required action per the procedure specified by listed parts. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-019-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSLs are based on increments of tardiness for competing required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider performing required action per the procedure specified by listed parts. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:
There are four requirements in PRC-024-1. Two of the Requirements (R1 and R2) were assigned a "Medium" VRF and the remaining two requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

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VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The “Lower” VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The “Lower” VRF assigned is based on the reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Exhibit E

Summary of the Reliability Standard Development Proceeding and Complete Record of Development of Proposed Reliability Standard

Exhibit E — Summary of the Reliability Standard Development Proceeding and Complete Record of Development of Proposed Reliability Standard

The development record for the proposed Reliability Standards is summarized below.

I. Overview of the Standard Drafting Team

When evaluating proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of four industry experts with a diversity of experience. A detailed set of biographical information for each of the team members is included along with the drafting team roster in **Exhibit F**.

II. Standard Development History

A. SAR Development

A Standard Authorization Request ("SAR") was submitted on April 3, 2007 and was posed for a 30-day public comment period from April 20, 2007 to May 21, 2007. There were 16 sets of comments, including comments from 63 different individuals from more than 35 organizations representing 7 of the 10 Industry Segments. In response to the comments received, the SAR drafting team revised the SAR for Project 2007-09 Generator Verification as follows:

- Added the Generator Operator and Reliability Coordinator as reliability functions that may have responsibilities in the proposed standards.
- Added language to clarify that the standard drafting team will consider the Phase III & IV field test results when developing the standards associated with this project.

The SAR was modified on June 14, 2007.

B. First Posting

MOD-026-1 and PRC-024-1 were posted for a 45-day formal comment period from February 17, 2009 to April 2, 2009. MOD-026-1 received 45 sets of comments, including comments from more than 100 different people from over 50 companies representing 8 of the 10

[1] Section 215 (d)(2) of the Federal Power Act; 16 U.S.C. §824o(d)(2)(2013).

industry segments. The standard drafting team considered stakeholder comments and made the following changes based on those comments:

- The standard drafting team consulted the Functional Model Working Group (FMWG), who rendered the opinion that the Generator Owner should be responsible for model verification, not the Generator Operator. Based on consultation with the FMWG, and supported by the majority of industry comments, the standard drafting team changed the applicability from the Generator Operator to the Generator Owner.
- The layout and the formatting of the standard were significantly updated. Periodicity has been moved to a separate attachment, as the standard drafting team determined that it is not a stand-alone reliability requirement.

For PRC-024-1, there were 43 sets of comments, including comments from more than 100 different people from over 60 companies representing 9 of the 10 industry segments. The standard drafting team considered stakeholder comments and made the following changes to PRC-024-1 based on those comments:

- The drafting team revised the purpose to clarify that new generators must be capable of riding through voltage and frequency excursions and expected unit performance during frequency and voltage excursions must be communicated to entities that monitor or model the associated generator.
- With respect to applicability, the standard drafting team determined that only the Generator Owner has responsibilities required by this NERC Standard. The "facility applicability" language that duplicated the language from the Compliance Registry Criteria is not necessary to include in the applicability section of the standard, and was removed. The team added a footnote to both Requirements R1 and R2 to clarify that the requirements in the standard do not require any entity to have frequency or voltage protective relaying installed or activated on its units.
- With respect to Requirement R1, the standard drafting team modified the sequence of the wording in the requirement; replaced the range of VRFs based on MVA to a single VRF for consistency with other standards; added the following as an additional criterion under which the generating unit may not trip: when the transmission system frequency rate of change is less than 2.5 Hz/second with a total change of up to 1.0 Hz.
- With respect to Requirement R2, the standard drafting team modified the language to clarify that the intent is to address trippings associated with events external to the generator; added more specificity to each of the criterion under which the generator unit may not trip; and replaced the range of VRFs based on MVA to a single VRF for consistency with other standards.

- Requirements R3 and R4 were merged and moved so that it is the last requirement, R7, so that the sequence of requirements is in chronological order.
- The language of Requirement R5 was modified and simplified for clarify regarding the required documentation of equipment limitations.
- A new Requirement was drafted to require Generator Owners to provide requesting entities with specific documentation to support an estimate of a unit's performance during Frequency/Voltage Excursions for modeling and study accuracy.
- The standard drafting team developed the off nominal frequency curve (Attachment 1) in coordination with the NERC UFLS Standard Drafting Team. The 57.8 Hz setting for generator underfrequency and 58 Hz for UFLS is to ensure that the UFLS will have a chance to arrest the system frequency decline before reaching the minimum permissible frequency for generators. The intent of the curves is to ensure that the generators do not trip when the frequency is within the area bounded by the high and low frequency curves. When the frequency excursion reaches outside the high or low curve, the generator is allowed to trip.
- The standard drafting team updated Attachment 2 to add more clarity on the calculations for the voltage ride through curve.

MOD-024-2 was posted for a 30-day public comment period from January 18, 2010 to February 18, 2010. There were 47 sets of comments, including comments from more than 130 different people from over 60 companies representing 8 of the 10 industry segments. The standard drafting team considered stakeholder comments and made the following changes to MOD-024-2 based on those comments:

- The requirement for the Resource Planner and Planning Coordinator to provide the Generator Owner with schedules and temperature adjustments was deleted, and the applicability section of the standard was revised to omit the Planning Coordinator and Resource Planner.
- The standard drafting team combined the requirements of MOD-024 and MOD-025 into MOD-025. Under the combined standard, all applicable units will be verified for both real and reactive power capability just once every five years. To avoid having many units requiring verification in any one year, the initial implementation period proposed requires verification of 20% of an entity's units each year.

MOD-025-2, MOD-027-1 and PRC-019-1 were posted for a formal 30-day comment period from June 15, 2011 to July 15, 2011. There were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing 9 of the 10 industry segments.

The standard drafting team considered stakeholder comments and made the following changes to MOD-025-2 based on those comments:

- Language was added to recommend that the AVR be in automatic control while conducting reactive capability testing, but that reactive capability testing must be done even if the AVR is not available.

The standard drafting team considered stakeholder comments and made the following changes to MOD-027-1 based on those comments:

- The standard drafting team expanded the applicability of MOD-027-1 to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities;
- Corrections of various typos in the body of the standard, the VSLs, and in Attachment 1;
- Extended the time to comply with Requirement 1 from 30 to 90 days;
- Modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base loaded unit is considered verified);
- Modified Attachment 1 (Periodicity Table) to clarify establishing the Initial Ten Year Unit Verification Period Start Date;
- Reduced the maximum time allowed between capture of an event and completing model verification from two years to one year;
- Referenced the NERC GADS document for references to capacity factor in the draft standard; and
- Included partial load rejection as a potential test to obtain a recording of the equipment response to be used in model verification.

The standard drafting team considered stakeholder comments and made the following changes to PRC-019-1 based on those comments:

- The example diagrams added that they are drawn at nominal voltage and frequency;
- The formula for calculating the radius of the SSSL was corrected;
- The items “under-excited limiters or minimum excitation limiters” and “over-excited limiters or maximum excitation limiters” have been placed in the bulleted list of the standard;
- The SDT changed “protective” to “protection” within the standard to be consistent with Section G; and
- The SDT added a reference document for use in calculation of SSSL.

C. Second Posting

MOD-026-1 and PRC-024-1 were posted for a 45-day formal public comment period from June 15, 2011 to August 1, 2011, with an initial ballot and non-binding poll from July 22, 2011 to August 1, 2011. For both standards, there were 66 sets of comments, including comments from approximately 185 different people from approximately 120 companies representing all 10 of the 10 industry segments. MOD-026-1 received a quorum of 90.25% and an approval rating of 46.53%. PRC-024-1 received a quorum of 90.82% and an approval of 18.23%.

The standard drafting team considered stakeholder comments and made the following changes to MOD-026-1 based on those comments:

- Correcting several VSL grammatical errors and ensuring consistency between the VSL "increment for tardiness" time period specified and the Requirement language.
- An additional condition, row 12, was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service.
- The format and column information of Attachment 1 was revised for clarity.
- The typographical errors in R2.1.1 language was corrected to clearly state expectation that "the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance."
- The language of R2.1.4 was revised to align with the style of R2.1.6.
- To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).
- There was some confusion regarding the treatment of small units at plants. The SDT modified the language in the Applicability / Facilities section for clarity and for consistency to the extent possible with the other draft standards in the Generation Verification effort.

The standard drafting team considered stakeholder comments and made the following changes to PRC-024-1 based on those comments:

- The two new terms proposed in the standard were removed. The voltage and frequency excursion values are now located in the requirements where they apply.
- Attachment 1 (Off Nominal Frequency Capability Curve) was revised to clarify the "no trip" zone.
- Attachment 2 (Voltage Ride-Through Time Duration Curves) has been clarified. The per unit voltage base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES). In addition, the definition was modified to include the phrase, "voltages in the curve assume minimum phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum phase-to-ground or phase-to-phase voltage for the high voltage duration curve."
- The Requirement Parts were revised in Requirement R1. Part 1.5 was moved into the body of R1.
- Requirement Part 2.1.1 was removed from Requirement R2. The body of the requirement and the remaining Parts were modified to clarify intent.
- Requirement R3 was changed to clarify the intent of non-protection system limitations and when such limitations must be addressed.

MOD-025-2, MOD-027-1 and PRC-019-1 were posted for a 45-day formal comment period from February 29, 2012 to April 16, 2012 with an initial ballot and non-binding poll from April 6, 2012 to April 16, 2012. There were 57 sets of comments, including comments from approximately 159 different people from approximately 51 companies representing 9 of the 10 industry segments. MOD-025-2 received a quorum of 88.28% with an approval rating of 41.09%. MOD-027-1 received a quorum of 88.04% with an approval rating of 36.84%.

For PRC-019-1, there were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing 9 of the 10 industry segments. PRC-019-1 received a quorum of 88.04% with an approval rating of 48.70%.

D. Third Posting

MOD-026-1 and PRC-024-1 were posted for a formal 30-day public comment period from February 29, 2012 to March 29, 2012 with a successive ballot from March 19, 2012 to March 29, 2012. There were 53 sets of comments, including comments from approximately 127 different people from approximately 88 companies representing 9 of the 10 industry segments. MOD-026-1 received a quorum of 81.45% and an approval rating of 61.21%. PRC-024-1 received a quorum of 80.38% and an approval of 41.09%.

The standard drafting team considered stakeholder comments and made the following changes to MOD-026-1 based on those comments:

- Included the term "impedance compensation" to Footnote 1 in the description of what constitutes an excitation control system for synchronous machines.
- Clarified that the response by the Transmission Planner to the Generator Owner concerning the results of testing the model useability is required to be a written response (R6). Also, for ease of reading, moved the last sentence in the requirement to after the Requirement Parts 1-3.
- Revised the first sentence in R1 to read: "Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request:" Stakeholders believed the previous language was not as clear as it could be, so the standard drafting team made this revision.
- Refined sub part 2.1.2 to read: "Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed)."

The standard drafting team considered stakeholder comments and made the following changes to PRC-024-1 based on those comments:

- The standard drafting team noted that some stakeholders were still unclear if the activities described in Requirement R4 were to be performed by request only, so the standard drafting team rearranged the sentences to make that more clear. Some stakeholders pointed out the RCs and TOPs can request such information via requirements in other standards (IRO-010-1a and TOP-003-2), so these two functional entities were removed from this requirement.
- Based on comments from a majority of stakeholders, Requirement R5 (along with its associated Measure M5 and VSL's) was removed from the Standard. The standard drafting team believes that Requirement R4 achieves the reliability objective of Paragraph 1787 of FERC Order No. 693 that Requirement R5 was written to address.

MOD-025-2, MOD-027-1 and PRC-019-1 were posted for a 30-day formal public comment period from September 28, 2012 to October 31, 2012 with a successive ballot and non-binding poll from October 19, 2012 to October 31, 2012.

For MOD-025-2, there were 48 sets of comments, including comments from approximately 155 different people from approximately 100 companies representing 8 of the 10 industry segments. MOD-025-2 received a quorum of 83.61% and an approval rating of 68.31%.

For-MOD-027-1, there were 46 sets of comments, including comments from approximately 152 different people from approximately 98 companies representing 9 of the 10 industry segments. MOD-027-1 received a quorum of 82.34% and an approval rating of 71.53%.

For PRC-019-1 there were 47 sets of comments, including comments from approximately 153 different people from approximately 99 companies representing 9 of the 10 industry segments. PRC-019-1 received a quorum of 82.07% and an approval rating of 70.64%.

E. Fourth Posting

MOD-026-1 and PRC-024-1 were posted for a formal comment period from September 28, 2012 to October 31, 2012 with a successive ballot and non-binding poll from October 19, 2012 to October 31, 2012.

MOD-026-1 received a quorum of 75.55% and an approval of 76.50%. PRC-024-1 received a quorum of 75% and an approval rating of 57.24%.

MOD-025-2, MOD-027-1 and PRC-019-1 were posted for a recirculation ballot from December 12, 2012 to December 21, 2012. MOD-025-2 received a quorum of 86.89% and an approval rating of 73.06%. MOD-027-1 received a quorum of 86.68% and an approval rating of 74.27%. PRC-019-1 received a quorum of 85.87% and an approval rating of 73.63%.

F. Fifth Posting

PRC-024-1 was posted for a formal comment period from December 12, 2012 to January 11, 2013 with a successive ballot and non-binding poll from January 2, 2013 to January 11, 2013. PRC-024-1 received a quorum of 78.16% and an approval rating of 60.31%.

The standard drafting team considered stakeholder comments and made the following changes to PRC-024-1 based on those comments:

- Revised the title of the standard to “Generator Frequency and Voltage Protective Relay Settings” and the Purpose Statement to “Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.”
- Revised “generating unit(s)” to “applicable generating unit(s)” to reflect that the standard only applies to units that meet the registry criteria.
- Removed Requirement R4 from the standards because of ambiguous language and dubious limited reliability benefit.
- Revised Requirement R5 (now R4) to indicate that the trip settings to be provided are only those “associated with Requirements R1 and R2” and not all relays.
- Revised Requirement R2 so that the sentences were shorter and easier to read, and made conforming language changes in Requirement R1.

MOD-026-1 was posted for a recirculation ballot from December 12, 2012 to December 21, 2012. MOD-026-1 received a quorum of 79% and an approval rating of 79.36%.

G. Sixth Posting

PRC-024-1 was posted for a 30-day public comment period from January 25, 2013 to February 25, 2013, with a successive ballot and non-binding poll from February 15, 2013 to February 28, 2013. PRC-02401 received a quorum of 78.80% and an approval rating of 89.01%.

There were 29 sets of comments, including comments from approximately 90 different people from approximately 63 companies representing 7 of the 10 industry segments

The standard drafting team considered stakeholder comments and made the following changes to PRC-024-1 based on those comments:

- Added page numbers to first section of the standard.

- Added the word “generator” before “frequency protective relaying” (second line) in Requirement R1 and before “voltage protective relaying” (second line) in Requirement R2 so that the language mirrored the first line of each requirement.
- Added the phrase “for asynchronous generating units” to the first bullet of Requirement R1 to match the language in the analogous bullet 3 in Requirement R2.
- Added the phrase “the applicable generating unit(s)” to the third line of Requirement R2 to match the language in Requirement R1.
- Added the phrase “with generator frequency or voltage protective relays” to the second line of Requirement R3 to clarify the language.

H. Board of Trustees Approval

MOD-025-2, MOD-026-1, MOD-027-1 and PRC-019-1 were approved by the NERC Board of Trustees on February 7, 2013. PRC-024-1 was approved by the NERC Board of Trustees on May 9, 2013.

Project 2007-09
Generator Verification

Related Files

Status:
MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1 were adopted by the NERC Board of Trustees on February 7, 2013 and PRC-024-1 was adopted on May 9, 2013. All five standards will be filed together with the appropriate regulatory authorities.

Purpose/Industry Need:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

New standards to be finalized as part of this project are:

- PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024 — Generator Performance During Frequency and Voltage Excursions
- MOD-026 — Verification of Models and Data for Generator Excitation System Functions
- MOD-027 — Verification of Generator Unit Frequency Response

Standards to be revised as part of this project are:

- MOD-024 — Verification of Generator Gross and Net Real Power Capability
- MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

All six of the standards included in this project address generator verifications needed to support bulk power system reliability. All six of the standards included in this project were originally "Phase III & IV Planning Measures" that were translated into new or a proposed standards as part of the Version 0 translation effort. Stakeholders have already agreed that there is a reliability-related need for each of these standards as part of the work performed in association with the Phase III & IV Modeling SAR. In addition, each of the standards included in this project has some "fill in the blank" requirements assigned to the Regional Reliability Organization that need to be replaced with more specific "continent-wide" requirements before the standards are approved.

Draft	Action	Dates	Results	Consideration of Comments
Draft 7 **PRC-024-1** Clean **(262)**| Redline to Last Posted **(263)** Implementation Plan Clean **(264)** **Supporting Materials:** Consideration of Issues and Directives Clean **(265)** VRFs and VSLs Clean **(266)**	Recirculation Ballot Info **(267)** Vote>>	03/18/13 - 03/27/13 (closed)	Summary **(268)** Ballot Results **(269)**	
Draft 6 **PRC-024-1** Clean **(246)**| Redline to Last Posted **(247)** Implementation Plan	Successive Ballot and Non-Binding Poll Updated Info **(255)** Vote>>	02/15/13 - 02/28/13 (closed)	Summary **(257)** Ballot Results **(258)** Non-binding Poll Results **(259)**	

Clean (248)| Redline to Last Posted (249) **Supporting Materials:** Unofficial Comment Form (Word) (250) Consideration of Issues and Directives Clean (251)| Redline to Last Posted (252) VRFs and VSLs Clean (253)| Redline to Last Posted (254)	Formal Comment Period Info (256) Submit Comments>>		Comments Received (260)	Consideration of Comments (261)
Draft 5 **MOD-026-1** Clean (212)| Redline to Last Posted (213) **Implementation Plan** Clean (214)| Redline to Last Posted (215) **Draft 4** **MOD-025-2** Clean (216)| Redline to Last Posted (217) **Implementation**	Recirculation Ballot Info (240) Vote>>	12/12/12 - 12/21/12 (closed)	Summary (241) Ballot Results: MOD-025-2 (242) MOD-026-1(243) MOD-027-1(244) PRC-019-1(245)	

Plan Clean **(218)** | Redline to Last Posted **(219)** **MOD-027-1** Clean **(220)**| Redline to Last Posted**(221)** **Implementation Plan** Clean **(222)**| Redline to Last Posted **(223)** **PRC-019-1** Clean **(224)**| Redline to Last Posted **(225)** **Implementation Plan** Clean **(226)**| Redline to Last Posted **(227)** **Supporting Materials:** **VRFs and VSLs** MOD-026-1 **(228)** MOD-025-2 **(229)** MOD-027-1 **(230)** PRC-019-1 **(231)** **MOD-024-1 and MOD-025-2** Consideration of				

Issues and Directives Clean **(232)** | Redline to Last Posted **(233)** MOD-024-1 **(234)** MOD-025-1 **(235)** MOD-024-1 Mapping Document Clean **(236)**| Redline to Last Posted **(237)** MOD-025-1 Mapping Document Clean **(238)**| Redline to Last Posted **(239)**				
Draft 5 **PRC-024-1** Clean **(195)**| Redline to Last Posted **(196)** **Implementation Plan** Clean **(197)**| Redline to Last Posted **(198)** **Supporting Materials:** Unofficial Comment Form (Word) **(199)**	Successive Ballot and Non-Binding Poll Updated Info **(204)** Info **(205)** Vote>>	01/02/13 - 01/11/13 (closed)	Summary **(207)** Ballot Results **(208)** Non-binding Poll Results **(209)**	
	Formal Comment Period Info **(206)** Submit	12/12/12 - 01/11/13 (closed)	Comments Received **(210)**	Consideration of Comments **(211)**

Consideration of Issues and Directives Clean **(200)** | Redline to Last Posted **(201)** VRFs and VSLs Clean **(202)** | Redline to Last Posted **(203)**	Comments>>			
Draft 4 **MOD-026-1** Clean **(168)** | Redline to Last Posted **(169)** **Implementation Plan** Clean **(170)** | Redline **(171)** **PRC-024-1** Clean **(172)** | Redline to Last Posted **(173)** **Implementation Plan** Clean **(174)** | Redline **(175)**	Successive Ballot and Non-Binding Poll Updated Info **(183)** Info **(184)** Vote>>	10/19/12 - 10/31/12 (closed)	Summary **(186)** Ballot Results: MOD-026-1 **(187)** PRC-024-1 **(188)** Non-binding Poll Results: MOD-026-1 **(189)** PRC-024-1 **(190)**	
	Formal Comment Period Info **(185)** Submit	09/28/12 - 10/31/12 (closed)	Comments Received>> MOD-026-1 **(191)** PRC-024-1 **(192)**	Consideration of Comments>> MOD-026-1 **(193)** PRC-024-1 **(194)**

Supporting Materials: Unofficial Comment Forms (Word) MOD-026-1 **(176)** PRC-024-1 **(177)** **MOD-026-1** VRFs and VSLs Clean **(178)** | Redline **(179)** **PRC-024-1** Consideration of Issues and Directives **(180)** VRFs and VSLs Clean **(181)** | Redline **(182)**	Comments>> MOD-026-1 PRC-024-1			
Draft 3 **MOD-025-2** Clean **(127)** | Redline to Last Posted **(128)** **Implementation Plan** Clean **(129)** | Redline **(130)** **MOD-027-1** Clean **(131)** |	Successive Ballot and Non-Binding Poll Info **(153)** Vote>>	10/19/12 - 10/31/12 (closed)	Summary **(155)** Ballot Results: MOD-025-2 **(156)** MOD-027-1 **(157)** PRC-019-1 **(158)** Non-binding Poll Results: MOD-025-2 **(159)**	

Redline to Last Posted **(132)** **Implementation Plan** Clean **(133)**| Redline **(134)** **PRC-019-1** Clean **(135)**| Redline to Last Posted **(136)** **Implementation Plan** Clean **(137)** | Redline **(138)** **Supporting Materials:** Unofficial Comment Forms (Word) MOD-025-2 **(139)** MOD-027-1 **(140)** PRC-019-1 **(141)** **MOD-024-1 and MOD-025-2** Consideration of Issues and Directives **(142)** MOD-024-1 **(143)** MOD-025-1 **(144)** **MOD-024-1** Mapping Document Clean **(145)**| Redline to Last Posted **(146)**			MOD-027-1 **(160)** PRC-019-1 **(161)**	
	Formal Comment Period Info **(154)** Submit Comments>> MOD-025-2 MOD-027-1 PRC-019-1	09/28/12 - 10/31/12 (closed)	Comments Received>> MOD-025-2 **(162)** MOD-027-1 **(163)** PRC-019-1 **(164)**	Consideration of Comments>> MOD-025-2 **(165)** MOD-027-1 **(166)** PRC-019-1 **(167)**

MOD-025-2 Mapping Document Clean **(147)**| Redline **(148)** VRFs and VSLs Clean **(149)** **MOD-027-1** VRFs and VSLs Clean **(150)** **PRC-019-1** VRFs and VSLs Clean **(151)**| Redline **(152)**				
Draft 2 **MOD-025-2** Clean **(91)** | Redline to Last Posted **(92)** **Implementation Plan** Clean **(93)**| Redline **(94)** **MOD-027-1** Clean **(95)**| Redline to Last Posted **(96)** **Implementation Plan** Clean **(97)** | Redline **(98)**	Initial Ballot and Non-binding Poll Info (04/05/12) **(114)** Updated Info **(115)** Info **(116)** Vote>>	04/06/12 - 04/16/12 (closed)	Info **(118)** Full Records: MOD-025-2 **(119)** MOD-027-1 **(120)** PRC-019-1 **(121)** Non-Binding Polls: MOD-025-2 **(122)** MOD-027-1 **(123)** PRC-019-1 **(124)**	
	Formal	02/29/12 -	Comments	Consideration of Comments

PRC-019-1 Clean **(99)**| Redline to Last Posted **(100)** **Implementation Plan** Clean **(101)**| Redline **(102)**	Comment Period Info **(117)** Submit Comments>>	04/16/12 (closed)	Received **(125)**	**(126)**
Supporting Materials: Comment Form (Word) - Combines: MOD-025-2, MOD-027-1 and PRC-019-1 **(103)** **MOD-024-1 and MOD-025-2** Consideration of Issues and Directives **(104)** MOD-024-1 **(105)** MOD-025-1 **(106)** **MOD-024-1** Mapping Document **(107)** **MOD-025-1** Mapping Document **(108)** VRFs and VSLs Clean **(109)**| VRFs and VSLs Redline **(110)**	Join Ballot Pools for Each Individual Standard and Non-Binding Poll (6)>> MOD-025-2 MOD-027-1 PRC-019-1	02/29/12 - 03/29/12 (closed)		

MOD-027-1 VRFs and VSLS **(111)** **PRC-019-1** VRFs and VSLs clean **(112)**| VRFs and VSLs Redline **(113)**				
Draft 3 **MOD-026-1** Clean **(72)**| Redline to Last Posted **(73)** **Implementation Plan** Clean **(74)**| Redline **(75)** **PRC-024-1** Clean **(76)** | Redline to Last Posted **(77)** **Implementation Plan** Clean **(78)**| Redline **(79)** **Supporting Materials:** Comment Form (Word) - Combines MOD-026-1 and PRC-024-1 **(80)**	Successive Ballot Info **(84)** Vote>>	03/19/12 - 03/29/12 (closed)	Updated Summary **(85)** Summary **(86)** Full Records: (updated 4/2/12) MOD-026-1 **(87)** PRC-024-1 **(88)**	
	Formal Comment Period Submit Comments>>	02/29/12 - 03/29/12 (closed)	Comments Received **(89)**	Consideration of Comments **(90)**

(3/2/12 - Revised Background Section and Questions #1 and #3) MOD-026-1 VRFs and VSLs **(81)** PRC-024-1 Consideration of Issues and Directives **(82)** VRFs and VSLs **(83)**				
Draft 1 **MOD-025-2** Standard **(53)** Implementation Plan **(54)** **MOD-027-1** Standard **(55)** Implementation Plan **(56)** **PRC-019-1** Standard **(57)** Implementation Plan **(58)** **Supporting Materials:** Comment Form (Word) - MOD-025-	Formal 30-day Comment Period Updated Info **(66)** Info **(67)** Submit Comments>>	6/15/11 - 7/15/11 (closed)	Comments Received **(68)**	Consideration of Comments>> MOD-025-2 **(69)** MOD-027-1 **(70)** PRC-019-1 **(71)**

2 **(59)** Comment Form (Word) - MOD-027-1 **(60)** Comment Form (Word) - PRC-019-1 **(61)** MOD-024-1 **(62)** MOD-025-1 **(63)** MOD-024 Mapping Document **(64)** MOD-025 Mapping Document **(65)**				
Draft 2 **MOD-026-1** Clean **(33)** | last posted **(34)** **Implementation Plan (35)** **PRC-024-1** Clean **(36)** | last posted **(37)** **Implementation Plan (38)** **Supporting Materials:** Comment Form (Word) - MOD-026-1 **(39)**	Initial Ballot and Non-Binding Poll	7/22/11 - 8/01/11 (closed)	Updated Summary **(44)** Summary **(45)** Full Record MOD-026-1 **(46)** Full Record PRC-024-1 **(47)** Non-Binding Results MOD-026-1 **(48)** Non-Binding Results PRC-	Consideration of Comments>> MOD-026-1 **(51)** PRC-024-1 **(52)**

Comment Form (Word) - PRC-024-1 **(40)**			024-1 **(49)**	
	Formal 45-Day Comment Period Info **(41)** Submit Comments>>	6/15/11 - 8/01/11 (closed)	Comments Received **(50)**	
	Join Ballot Pool for MOD-026 Join Ballot Non-Binding Poll for MOD-026 Info **(42)**	6/15/11 - 7/15/11 (closed)		
	Join Ballot Pool for PRC-024 Join Ballot Non-Binding Poll for PRC-024 Info **(43)**			
Draft 1 MOD-024-2 Standard **(26)** Implementation Plan **(27)**	30-day Comment Period Info **(30)** Submit	01/18/10 - 02/18/10 (closed)	Comments Received **(31)**	Consideration of Comments **(32)**

Supporting Materials: Comment Form (Word) **(28)** Issues Database **(29)**	Comments>>			
Draft 1 MOD-026-1 Standard MOD-026-1 **(20)** **Supporting Materials:** Comment Form (Word) **(21)** MOD-026-1 Mapping Document **(22)**	45-day Comment Period Info **(23)** Submit Comments>>	02/17/09 - 04/02/09 (closed)	Comments Received **(24)**	Consideration of Comments **(25)**
Draft 1 PRC-024-1 Standard PRC-024-1 **(14)** **Supporting Materials:** Comment Form (Word) **(15)** PRC-024-1 Mapping Document **(16)**	45-day Comment Period Info **(17)** Submit Comments>>	02/17/09 - 04/02/09 (closed)	Comments Received **(18)**	Consideration of Comments **(19)**

Standard Drafting Team Nominations	Nomination Period Info **(12)** Submit Nomination **(13)**	07/17/07 - 07/30/07 (closed)		
SAR Version 2 Clean **(10)** | Redline to 1st posting **(11)**				
SAR Version 1 **(4)** **Supporting Material:** Field Test Results **(5)**	Comment Period Info **(6)** Submit Comments **(7)**	04/20/07 - 05/21/07 (closed)	Comments Received **(8)**	Consideration of Comments **(9)**
SAR Drafting Team Nominations SAR Version 1 **(1)**	Nomination Period Info **(2)** Submit Nomination **(3)**	04/18/07 - 05/02/06 (closed)		

Standard Authorization Request Form

Title of Proposed Standard	Generator Verification (Project 2007-09)
Request Date	April 3, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: Bob Millard	☒	New Standards
Primary Contact: Bob Millard	☒	Revision to existing Standards:
Telephone: (708) 588-9886 Fax:	☐	Withdrawal of existing Standard
E-mail: bob.millard@rfirst.org	☐	Urgent Action

Purpose

The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

New standards to be finalized as part of this project are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

Standards to be revised as part of this project are:

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

Industry Need

All six of the standards included in this project address generator verifications needed to support bulk power system reliability. All six of the standards included in this project were originally “Phase III & IV Planning Measures” that were translated into new or proposed standards as part of the Version 0 translation effort. Stakeholders have already agreed that there is a reliability-related need for each of these standards as part of the work performed in association with the Phase III & IV Modeling SAR. In addition, each of the standards included in this project has some “fill-in-the-blank” requirements assigned to the Regional Reliability Organization that need to be replaced with more specific “continent-wide” requirements before the standards are approved.

Specifically:

- MOD-024-1 and MOD-025-1 were approved by the NERC Board of Trustees but are “pending” with FERC because they include “fill-in-the-blank” requirements assigned to the Regional Reliability Organization (MOD-024-1 and MOD-025-1 require generator owners to verify the generator’s gross and net real and reactive power capability using an RRO established procedure).

- PRC-019-1, PRC-024-1, MOD-026-1 and MOD-027-1 are draft standards that were developed under the Phase III & IV Modeling SAR that have not been presented to the NERC Board of Trustees yet. These four standards contain “fill-in-the-blank” requirements assigned to the Regional Reliability Organization (RRO) which were appropriate when the standards were initially drafted but are not appropriate under current requirements for approval of enforceable standards. Work on these standards to remove the “fill-in-the-blank” requirements under the Phase III & IV Modeling SAR is not authorized and therefore cannot be completed under the Phase III & IV Modeling SAR because the modifications needed to make the standards enforceable are outside the scope of the original Phase III & IV SARs. To properly complete these standards, a new SAR is needed and the prior SAR need to be terminated (termination of the Phase III & IV Modeling SAR will be performed outside the work of this SAR).
    - This set of standards includes verification of the generator’s excitation system; verification of the generator’s frequency response; verification that the generator can remain connected during specified voltage and frequency excursions; and verification that the generator’s voltage regulator controls and limit functions have been coordinated with the generator’s capabilities and protective relays.
    - The field test for this set of standards has shown that a standard can be written to support these verifications.

Brief Description

The scope of this project includes:

- modifying the six standards associated with this project so they conform to the latest version of NERC’s Reliability Standards Development Procedure and the ERO Rules of Procedure,
- replacing the “fill-in-the-blank” requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners or operators of the bulk power system, and
- considering and addressing issues identified in FERC orders, including the modifications to MOD-024-1 and MOD-025-1 as proposed in FERC Order 693.

Detailed Description

The standards drafting team (SDT) will bring the six standards into conformance with the latest version of NERC's Reliability Standards Development Procedure and the ERO Rules of Procedure. In addition, the STD will consider and address all applicable FERC Orders, including FERC Order 693, and the following proposed changes for each of the six standards in this set of standards:

Draft PRC-019-1

- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generator owners that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft PRC-024-1

- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generators will remain connected during specified system frequency and voltage excursions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a requirement for the Transmission Owner and Generator Owner to coordinate protection systems
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

MOD-024-1:

- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with verification of generator gross and net real power capability
    - Consider requiring the generator owner to document the test conditions and the relationships between test conditions and generator output
- Assign responsibility to the appropriate functional entities as a result of updates to

the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a ‘time horizon’ for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the ‘levels of non-compliance’ with ‘violation severity levels’

MOD-025-1:
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of ‘continent-wide’ criteria for verification of models and data associated with verification of generator gross and net Reactive Power capability
  - Consider requiring verification of reactive power capability at multiple points over a unit’s operating range
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a ‘time horizon’ for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the ‘levels of non-compliance’ with ‘violation severity levels’

Draft MOD-026-1
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of ‘continent-wide’ criteria for verification of models and data associated with generator excitation system functions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a ‘violation risk factor’ and a ‘time horizon’ for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the ‘levels of non-compliance’ with ‘violation severity levels’

Draft MOD-027-1
- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of ‘continent-wide’ criteria for verification of models and data associated with generator unit frequency response
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the

Regional Reliability Organization

- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the 'levels of non-compliance' with 'violation severity levels'

Reliability Functions

The Standard Drafting Team will Consider Applicability to All Functional Entities *(Check box for each one that may apply.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.Yes
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure. Yes
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
Phase III&IV Modeling	This SAR dated 11/17/04 initiated work on all six standards, two of which have been approved by the NERC BOT and four of which are still in draft phase, as referenced above above. The SDT working on the four draft standards will be terminated and undertaken by the new SDT for this SAR.

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Maureen E. Long
Standards Process Manager

April 18, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement
Nomination Periods Open for Three Drafting Teams

The Standards Committee (SC) announces the following standards actions:

Nominations for Project 2007-09 Generator Verifications SAR Drafting Team (April 18–May 2, 2007)

The Standards Committee is seeking industry experts to serve on the Generator Verification SAR Drafting Team. This project calls for completing the final four Phase III & IV standards (PRC-019, PRC-024, MOD-026, and MOD-027) and for refinement of two standards that were approved in 2005 (MOD-024 and MOD-025).

- PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024 — Generator Performance During Frequency and Voltage Excursions
- MOD-024 — Verification of Generator Gross and Net Real Power Capability
- MOD-025 — Verification of Generator Gross and Net Reactive Power Capability
- MOD-026 —Verification of Models and Data for Generator Excitation System Functions
- MOD-027 — Verification of Generator Unit Frequency Response

The set of six standards all require generator verifications — either to ensure that generators will not trip off line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions or to ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

If you are interested in serving on this team, please complete this nomination form and return it to sarcomm@nerc.net with "GEN VER SARDT Nomination" in the subject line, no later than **May 2, 2007**.

Nominations for Project 2006-03 System Restoration and Blackstart Standard Drafting Team (April 18–May 2, 2007)

The Standards Committee is seeking additional industry experts to serve on the System Restoration and Blackstart Standard Drafting Team. This project calls for the modification of the following standards:

- EOP-005 — System Restoration Plans
- EOP-006 — Reliability Coordination — System Restoration
- EOP-007 — Establish, Maintain, and Document a Regional Blackstart Capability Plan
- EOP-009 — Documentation of Blackstart Generating Unit Test Results

This project involves upgrading the overall quality of the four standards; eliminating some gaps in the requirements; eliminating some ambiguity; and eliminating some "fill-in-the-blank" components. The Standards Committee has appointed the initial standard drafting team, but is seeking additional members, particularly from within the SPP and WECC regions.

If you are interested in serving on this team, please complete this nomination form and return it to sarcomm@nerc.net with "SRBS SDT Nomination" in the subject line, no later than **May 2, 2007**.

Nominations for Project 2007-02 Operating Personnel Communications Protocols SAR Drafting Team (April 18–May 2, 2007)

The Standards Committee is seeking additional industry experts to serve on the Operating Personnel Communications Protocols SAR Drafting Team. This SAR calls for the development of communications protocols for use by real-time system operators to improve situational awareness and shorten response time. The Standards Committee has appointed an initial SAR Drafting Team but is seeking additional nominations, particularly from the FRCC, NPCC, and SPP regions, from Canada, and from the generation and load-serving entity segments that will be affected by the proposed standard.

If you are interested in serving on this team, please complete this nomination form and return it to sarcomm@nerc.net with "OPS COM SARDT Nomination" in the subject line, no later than **May 2, 2007**.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please return this form to sarcomm@nerc.net by **May 2, 2007** with "GEN VER SARDT Nomination" in the subject line. For questions about the drafting team, please contact David Taylor at 609-651-5089 or david.taylor@nerc.net.

Name:	
Organization:	
Address:	
Office Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the Generator Verification SAR Drafting Team. Prefer experience in verifying or modeling generator capabilities or in coordinating generator protection with transmission protection. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):		**I represent the following Industry Segment (check one):**
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs, ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations and Regional Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Reliability Coordinator	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Coordinator	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
	☐ Market Operator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the Functional Model, which is downloadable from the following Web site: http://www.nerc.com/~filez/functionalmodel.html

Standard Authorization Request Form

Title of Proposed Standard	Generator Verification (Project 2007-09)
Request Date	April 3, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: Bob Millard	☒	New Standards
Primary Contact: Bob Millard	☒	Revision to existing Standards:
Telephone: (708) 588-9886 Fax:	☐	Withdrawal of existing Standard
E-mail: bob.millard@rfirst.org	☐	Urgent Action

Purpose

The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

New standards to be finalized as part of this project are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

Standards to be revised as part of this project are:

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

Industry Need

All six of the standards included in this project address generator verifications needed to support bulk power system reliability. All six of the standards included in this project were originally "Phase III & IV Planning Measures" that were translated into new or proposed standards as part of the Version 0 translation effort. Stakeholders have already agreed that there is a reliability-related need for each of these standards as part of the work performed in association with the Phase III & IV Modeling SAR. In addition, each of the standards included in this project has some "fill-in-the-blank" requirements assigned to the Regional Reliability Organization that need to be replaced with more specific "continent-wide" requirements before the standards are approved.

Specifically:

- MOD-024-1 and MOD-025-1 were approved by the NERC Board of Trustees but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization (MOD-024-1 and MOD-025-1 require generator owners to verify the generator's gross and net real and reactive power capability using an RRO established procedure).

- PRC-019-1, PRC-024-1, MOD-026-1 and MOD-027-1 are draft standards that were developed under the Phase III & IV Modeling SAR that have not been presented to the NERC Board of Trustees yet. These four standards contain "fill-in-the-blank" requirements assigned to the Regional Reliability Organization (RRO) which were appropriate when the standards were initially drafted but are not appropriate under current requirements for approval of enforceable standards. Work on these standards to remove the "fill-in-the-blank" requirements under the Phase III & IV Modeling SAR is not authorized and therefore cannot be completed under the Phase III & IV Modeling SAR because the modifications needed to make the standards enforceable are outside the scope of the original Phase III & IV SARs. To properly complete these standards, a new SAR is needed and the prior SAR need to be terminated (termination of the Phase III & IV Modeling SAR will be performed outside the work of this SAR).
    - This set of standards includes verification of the generator's excitation system; verification of the generator's frequency response; verification that the generator can remain connected during specified voltage and frequency excursions; and verification that the generator's voltage regulator controls and limit functions have been coordinated with the generator's capabilities and protective relays.
    - The field test for this set of standards has shown that a standard can be written to support these verifications.

Brief Description

The scope of this project includes:

- modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Rules of Procedure,
- replacing the "fill-in-the-blank" requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners or operators of the bulk power system, and
- considering and addressing issues identified in FERC orders, including the modifications to MOD-024-1 and MOD-025-1 as proposed in FERC Order 693.

Detailed Description

The standards drafting team (SDT) will bring the six standards into conformance with the latest version of NERC's Reliability Standards Development Procedure and the ERO Rules of Procedure. In addition, the STD will consider and address all applicable FERC Orders, including FERC Order 693, and the following proposed changes for each of the six standards in this set of standards:

Draft PRC-019-1

- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generator owners that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft PRC-024-1

- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generators will remain connected during specified system frequency and voltage excursions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a requirement for the Transmission Owner and Generator Owner to coordinate protection systems
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

MOD-024-1:

- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with verification of generator gross and net real power capability
    - Consider requiring the generator owner to document the test conditions and the relationships between test conditions and generator output
- Assign responsibility to the appropriate functional entities as a result of updates to

the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the 'levels of non-compliance' with 'violation severity levels'

MOD-025-1:
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with verification of generator gross and net Reactive Power capability
  - Consider requiring verification of reactive power capability at multiple points over a unit's operating range
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft MOD-026-1
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with generator excitation system functions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft MOD-027-1
- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with generator unit frequency response
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the

Regional Reliability Organization

- Add a ‘violation risk factor’ and a ‘time horizon’ for each requirement
- Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
  - Replace the ‘levels of non-compliance’ with ‘violation severity levels’

Reliability Functions

The Standard Drafting Team will Consider Applicability to All Functional Entities *(Check box for each one that may apply.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
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☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
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☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.Yes
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure. Yes
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
Phase III&IV Modeling	This SAR dated 11/17/04 initiated work on all six standards, two of which have been approved by the NERC BOT and four of which are still in draft phase, as referenced above above. The SDT working on the four draft standards will be terminated and undertaken by the new SDT for this SAR.

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

ERCOT Generator Verification

SAR Drafting Team Kick-off Meeting
Florida Reliability Coordinating Council Offices
Tampa, FL
June 18-19, 2007

Vance Beauregard, American Electric Power
Jack Thormahlen, Lower Colorado River Authority

Background -- Documents

- ERCOT Protocols
  - Rules of the market
- ERCOT Operating Guides
  - Additional details regarding reliability

Background – Action Plan

- Dynamics Working Group
  - Reviewed Operating Guides to identify where draft requirements were met
  - Prepared Operating Guide revisions to address remaining gaps
  - Submitted Operating Guide Revision Request (OGRR)

Background – Action Plan

- Reliability and Operations Subcommittee (ROS)
  - Tabled Operating Guide Revision Request (OGRR)
  - Formed an ad hoc task force

Background – Action Plan

- Ad Hoc Task Force
  - Composed of 17 market participants
  - Reviewed Operating Guides to identify where draft requirements were met
  - Reviewed OGRR and suggested changes
  - Will resubmit OGRR at appropriate time

Formality of Actions Taken

- ROS directed the formation of the Ad Hoc Task Force
- Market Participants invited to participate
  - Combined cycle plants and steam turbine plants
  - Hydro
  - Coal fired and Nuclear
  - Transmission Providers
- Ad Hoc Task work has not been reviewed by ROS

Different from Normal Process

- Normal Process Approvals
  - Reliability and Operations Subcommittee
  - Technical Advisory Committee
  - ERCOT Board of Directors
- NERC Field Test Request
  - Actions have not gone through the normal reviews and approval processes in order to provide a timely response to NERC

Actual Testing / Verification

- For most of the testing the past experience and testing was sufficient
- Market Participants have revised the OGRR to insure the fidelity of the model
- No actual tests were performed

Executive Summary of Results

- ERCOT Protocols
  - 5.2.2 Operating Standards
    - Comply with Good Utility Practice, NERC and ERCOT standards
  - 5.8.2 Primary Frequency Control Measurements
    - Shall be performed to ensure conformance to criteria

Executive Summary of Results

- ERCOT Protocols (continued)
  - 5.8.1.2 Reporting
    - Tests to be reported to ERCOT in 30 days
  - 6.10.3.5 Reactive Supply
    - Each unit submits a CURL to ERCOT
  - 6.10.2 Capacity Testing Requirements
    - Test of net dependable capability seasonally

Executive Summary of Results

- ERCOT Operating Guides
  - 1.2 Document Relationship
  - 1.3 Process for Operating Guide Revision
  - 2.2.4 Automatic Voltage Regulators and Power System Stabilizers
  - 2.2.5 Turbine Speed Governors
  - 2.2.6 Performance/Disturbance/ Compliance Analysis

Executive Summary of Results

- ERCOT Operating Guides (2)
  - 2.9.1 Automatic Firm Load Shedding
  - 2.9.2 Generators Under-Frequency relay coordination
  - 3.1.4 Power Generation Companies testing and modeling requirements
  - 3.1.4.3.1 Corrected Unit Reactive Limits (CURL)

Executive Summary of Results

- ERCOT Operating Guides (3)
  - 3.1.4.5 Automatic Voltage Regulators and Power System Stabilizers (tests)
  - 3.1.4.6 Protective Relaying Requirement
  - 5.1.6.2 System Modeling Information
  - 7.2.5.3 Specific Application Considerations

Status of References

- ERCOT Protocols and Operating Guides are approved as of May 1, 2007
- Responses to the draft standards were reviewed by the ad hoc task force
- The OGRR is evolving to reflect comments

Difference from Proposed Requirements

- Operating Guides need more specificity
- OGRR will provide necessary language to meet the proposed draft standards

Extent of Actual Checking of Documents

- Review of historical testing processes
- Testing is required under ERCOT Protocols and Operating Guides
- Modeling information is also required
- Gap identified in the feedback loop for model verification
- OGRR will address the issues

Are Procedures Feasible?

- Procedures were deemed to be feasible and reasonable
- Gap in feedback loop needs to be addressed to make sure verification tests produce worthwhile results

Were Verifications Valuable?

- Present tests are valuable for ERCOT purposes, but do not result in model verification
- The OGRR will ensure that models will be verified and improved

Anticipated Cost and Time

- Cost of verifying models is unknown
- Complete implementation of the OGRR could take up to 3 years

Changes to Draft Standards

- No changes needed from ERCOT perspective
- Requirements should not be written in a way to prohibit verification of the models using actual disturbance data

Implementation Plan

- ERCOT has no comments on the implementation plan or timeline
- The final form of the ERCOT OGRR will likely depend on what the final NERC standard looks like

Important Regional Point

- Requirements should not be written in a way to prohibit verification of the models using actual disturbance data

Details/Appendices/Attachments

- Regional documents and procedures
- See attached ERCOT Protocols and Operating Guides

Mapping

- Mapping of the draft standards to the ERCOT Protocols and Operating Guides and OGRR188 is contained in the appendix

Red-lined Draft Standards

- ERCOT does not propose any changes to the draft standards
- Verification will be done primarily by using actual disturbance data

Ad Hoc Task Force Involvement

Date: March 26, 2007

Host: Jack Thormahlen

Purpose of Meeting: NERC Field Test Meeting DSC A505

	Printed Name	Signature	Employee ID# or Business Name
1.	JACK THORMAHLEN	[signature]	3901 LCRA
2.	Billy Shaw	[signature]	IPA BSHAW@ANPOWER.Com
3.	Larry Glass	[signature]	LCRA ext 7123
4.	JOHN MOORE	[signature]	STEC
5.	Guy Nelson	[signature]	0983 LCRA
6.	Chris Cromer	[signature]	NRG Texas
7.	Darrell Scruggs	[signature]	CALPINE
8.	DAN MAKELKI	[signature]	AEP
9.	Shun-Hsien Huang	[signature]	ERCOT shuang@ercot.com
10.	Ron Wheeler	[signature]	Dynegy
11.	Farzaneh Tafreshi	[signature]	ERCOT
12.	CESAR SEYMOUR	[signature]	CESAR.SEYMOUR@SUEZENERGYNA.COM
13.	KEN CHUI	[signature]	AUSTIN ENERGY.
14.	Orlando Brandon	[signature]	FPL

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Ad Hoc Task Force Involvement

Date: March 26, 2007

Host: Jack Thormahlen

Purpose of Meeting: NERC Field Test Meeting DSC A505

	Printed Name	Signature	Employee ID# or Business Name
15.	TIM MORTENSEN	Tim Mortensen	ERCOT tmortensen@ercot.com
16.	WES WOITT	Wesley Woitt	wesley.woitt@centerpointenergy.com
17.	Jerry Ward	J Ward	TXU
18.	Rick Terrill	Rick Terrill	TXU
19.	VANCE BEAUREGARD	Vance Beauregard	AEP
20.	Reed Hurley	Reed Hurley	LCRA Fayette Power Plt
21.			
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Midwest Reliability Organization

Generator Testing Review Task Force

Phase III – IV Field Testing Results

June 18 - 19, 2007

GTRTF Overview

- MAPP Generator Testing Working Group
  - ✓Formed in 1998
  - ✓Developed MAPP Generator Testing Requirements
- MRO GTRTF
  - ✓Formed in Sept. 2006
  - ✓Developed MRO Generator Testing Guidelines for the four Field Test standards and two approved standards (real and reactive power testing)
  - ✓Participation from American Transmission, Manitoba Hydro, Muscatine W&P, Wisc Public Service, Xcel Energy (NSP)

MIDWEST RELIABILITY ORGANIZATION

MOD-026 Excitation Response Verification

- Field Testing Performed
  - ✓ 31 Units tested to MAPP guidelines
  - ✓ 11 Units tested or to be tested to MRO guidelines
- Requirements reasonable, achievable
- Testing can be costly – $5k to $50k+ (includes 027)
- Initial matching to measured data time consuming
  - ✓ Parameter optimization program would be very helpful.
- Verification through disturbance monitoring
  - ✓ Expected to be less costly, but not field tested
  - ✓ Recommend removing requirement for step response test (R1.4.5) to allow disturbance monitoring

MIDWEST RELIABILITY ORGANIZATION

MOD-027 Frequency Response Verification

- Field Testing Performed
  - ✓ 17 Units tested to MAPP guidelines
  - ✓ 8 Units tested or to be tested to MRO guidelines
- Requirements reasonable, achievable
- Testing can be costly – $5k to $50k+ (includes 026)
- Initial matching to measured data time consuming
  - ✓ Parameter optimization program would be very helpful.
  - ✓ Some units could not match PSS/E model to response – had to use detailed manufacturer model
- Verification through disturbance monitoring
  - ✓ Expected to be less costly, but not field tested
  - ✓ No function in PSS/E for injecting an arbitrary frequency signal at the model speed reference point.

MIDWEST RELIABILITY ORGANIZATION

PRC-019 Coordinating Control & Protection

- Field Testing Performed
  - ✓ 166 Units analyzed, most to the MAPP guidelines
- Requirements reasonable, achievable
- Testing relatively inexpensive
  - ✓ Limiter verification done with MOD-026 testing
  - ✓ Relay verification done per PRC-005
- Several cases of mis-coordination found
  - ✓ Mostly related to UEL, LOF Relay and SSSL
- Recommended changes
  - ✓ R2.1.3 (plot prime mover rating) seems of questionable value.

MIDWEST RELIABILITY ORGANIZATION

PRC-024 Voltage & Frequency Excursions

- Field Testing Performed
  - ✓ No physical testing. 2 Units analyzed for voltage criteria by PSS/E simulation.
- Requirements reasonable, achievable
  - ✓ Frequency criteria must comply with regional UFLS program.
  - ✓ Standardized, reasonable voltage criteria needs to be developed.
- No physical generator testing involved
  - ✓ Frequency relay verification done per PRC-005
  - ✓ Voltage ride-through done by simulation
- Recommended changes
  - ✓ Existing units should be exempt from voltage criteria (beyond IEEE or ANSI mfr req's) until upgrading.

MIDWEST RELIABILITY ORGANIZATION

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Phase III-IV Field Test Report
Prepared by the SERC EC Generator Standard Field Test Task Force
June 15, 2007

BACKGROUND

The purpose of this report is to document the activities of the SERC EC Generator Standard Field Test Task Force in the NERC Field Tests of proposed Reliability Standards for MOD-026 (Verification of Models and Data for Generator Excitation System Functions); MOD-027 (Verification of Generator Unit Frequency Response); PRC-019 (Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection); and PRC-024 (Generator Performance During Frequency and Voltage Excursions).

SERC EC GSFT-TF members include representatives from the US Army Corps of Engineers-Mobile District (USACE), Dominion, Entergy, SCE&G, and Southern. In support of the Field Test activities by SERC member Generator and Transmission Owners, the GSFT-TF developed the following Field Test Guidelines and Reporting Forms:

1) SERC Field Test Guidelines – Verification of Models and Data for Generator Excitation System Functions - NERC Reliability Standards MOD-026; [SERC MOD-026 Field Test Guideline Rev 1 (1-11-07).doc]

2) MOD-026 SERC Field Test Reporting form; [SERC MOD-026 Field Test Reporting Form Rev 0 (1-11-07).doc]

3) SERC Field Test Guidelines – Verification of Generator Unit Frequency Response – NERC Draft Reliability Standard MOD-027; SERC MOD-027 Field Test Guideline Rev 0 (3-2-07).doc

4) MOD-027 SERC Field Test Reporting Form; SERC MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc

5) SERC Field Test Guidelines – Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection; SERC PRC-019 Field Test Guideline Rev 0 (8-28-06).doc

6) PRC-019 SERC Field Test Reporting Form; SERC PRC-019 Field Test Reporting Form Rev 1 (11-2-06).doc

7) SERC Field Test Guidelines – Generator Performance during Frequency and Voltage Excursions; SERC PRC-024 Field Test Guidelines Rev 0 (3-2-07).doc

8) Generator Owner PRC-024 SERC Field Test Reporting Form; SERC PRC-024 GO Field Test Reporting Form Draft 0 (3-13-07).doc

9) Transmission Owner PRC-024 SERC Field Test Reporting Form; SERC PRC-024 TO Field Test Reporting Form Draft 0 (3-13-07).doc

The purpose of the aforementioned Field Test Guidelines and Reporting Forms are to provide assistance to the SERC volunteer members that conducted the Field Tests. As such, the documents do not contain content that constitutes a requirement on any SERC entity.

Following is Field Test background information specific to each proposed Reliability Standard:

<u>MOD-026-1: Verification of Models and Data for Generator Excitation System</u>

Generation Owner entities within SERC that participated in this field test include the USACE-Mobile District, Dominion, SCE&G, and Southern. Though the current version of the proposed Reliability Standard does not include applicability to Transmission Owners, TO entities within SERC that participated include the USACE-Mobile District, Dominion, Entergy, and Southern. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable regarding the GSFT-TF developed Field Test Guidelines and Reporting Forms. Even before the start of the Field Test, SERC had approved the Supplement which called for the open step in voltage testing and subsequent excitation model verification over a multi year phase in period. As such, all of the entities had either planned or had performed some exciter model verifications in the past.

<u>MOD-027-1: Verification of Generator Unit Frequency Response</u>

Generation Owner entities within SERC that participated in this field test include the USACE-Mobile District, Dominion, Entergy, SCE&G, and Southern. Though the current version of the proposed Reliability Standard does not include applicability to Transmission Owners, TO entities within SERC that participated include Dominion, Entergy, and Southern. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable regarding the GSFT-TF developed Field Test Guidelines and Reporting Forms.

As documented in the Field Test Guidelines, the GSFT-TF attempted to utilize an event based approach to Validate unit frequency response for a sample number of generators. While it is known that WECC has developed and utilize this type of approach, it has not been previously utilized in SERC. A significant part of the effort was spent finding an appropriate software tool to re-create the frequency event and validate the models. Generator response data for two specific frequency excursion events were compared to unit frequency responses predicted by the unit's speed / load control dynamic models.

<u>PRC-019-1: Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection</u>

Generation Owner entities within SERC that participated in this field test include the USACE-Mobile District, Dominion, Entergy, and Southern. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable of the GSFT-TF developed Field Test Guidelines and Reporting Forms. Though not obligated through any RRO or NERC requirements, Southern Company Generation has been performing generator coordination studies for a few years. The other entities had not recently conducted these coordination studies until this Field Test. As such, they had to implement through significant start up processes.

PRC-024-1: Generator Performance during Frequency and Voltage Excursions

Generation Owner entities within SERC that participated in this field test include Dominion, Southern, and USACE-Mobile District. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable regarding the GSFT-TF developed Field Test Guidelines and Reporting Forms. As part of SERC UFLS studies, efforts have been made in the past to identify units with under frequency turbine protection that would not coordinate with UFLS relays. There has been some limited investigation of low voltage ride through (LVRT) capabilities of units in SERC. Draft frequency excursion and LVRT curves have been drafted and discussed in SERC groups, with the intent of adding them to SERC Supplements in support of Planning Standards. However, the efforts were put on hold with the abolishment of the Planning Standards. Therefore, before these Field Test activities, there has been little formal investigation of unit ride through capability for frequency and voltage excursions within SERC.

EXECUTIVE SUMMARY

MOD-026-1: Verification of Models and Data for Generator Excitation System

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in MOD-026-1. Two SERC Generator Owner entities actually performed the activities detailed in the completed SERC Field Test Guidelines (Attachment 1), while 2 utilized outside consultants to address some of the Requirements. The GSFT-TF believes these activities would constitute compliance with the proposed MOD-026-1 NERC Reliability Standard as currently drafted.

Four Generator Owners, and the associated Transmission Planning entities, within SERC participated in the Field Test of MOD-026. One Generator Owner and Transmission Planning entity have been performing the Open Step in Voltage tests and subsequent exciter model verification for a number of years. Prior to the Field Tests, the other entities had limited experience. Two entities relied on consultants to perform the Open Step in Voltage test, either as part of unit start up activities, or through a specific contract for excitation system model verification. It should be noted that most entities will require the use of consultants to perform these tests and the model validations due to a lack of in-house expertise. It was observed that using consultants is expensive, roughly $20,000 to 30,000 for one unit.

Open Step in Voltage tests are performed when the unit is at synchronous speed but at no load (i.e., functionally, the generator breaker is open). Therefore, it is best performed when the generator is coming off-line or is about to be put on-line. Thus, scheduling of these tests can be problematic.

Satisfactorily completing the requirements in draft Reliability Standard MOD-026-1 does improve the accuracy of the exciter models used in dynamic simulations. But it is noted that the effort required to verify the exciter model with the Open Step in Voltage tests can be laborious and time consuming. While the major dynamic simulation software vendors do have a number of exciter models in their library, it is becoming commonplace for Generator Owners to execute partial excitation system change outs. For example, conversion of a rotating field excitation system from an analog voltage regulator to a static voltage regulator results in an hybrid system that does not fit well with any standard library models. Significant effort, including requests for additional unit data from generator manufacturers, resulting in required use of an exponentially more complicated exciter model was required to obtain good model verification.

It is difficult to accurately project the cost, time, and level of benefits for all applicable entities in the region to implement the procedures to verify excitation system and PSS models. The current amount of actual generating plant capability in Commercial Operation in SERC approaches 260 GW. The GSFT-TF recommends that all units below 75 MVA or interconnected at voltages less than 100 kV should be exempt from the model verification requirements. Also, rigorous configuration control processes and sister units philosophy should be allowed so that model verification efforts can potentially be applicable to multiple units. Assuming the Reliability Standard is developed with reasonable exemption criteria, and allowances for configuration control / sister unit philosophies, the SERC GSFT-TF would recommend a 7 year phase in period (Effective date 2 years after adoption, then 20% per year for 5 years).

As marked up by the GSFT-TF in the redline versions of the current draft of MOD-026 (MOD-026_Draft for Field Test (GSFT-TF revised 5-3-07).doc), the GSFT also recommends:

1) A list of acceptable models be maintained, along with a procedure for revising the list of acceptable models (must be available in the major dynamic simulation software libraries).
2) Additional specificity regarding PSS commissioning tests.

<u>MOD-027-1: Verification of Generator Unit Frequency Response</u>

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in MOD-027-1. Five SERC Generator Owner entities attempted to perform the activities detailed in the completed SERC Field Test Guidelines. Upon inspection of captured event data for both the frequency excursion events, one of the Generator Owners found that none of his units were in an operating state conducive to responding to under frequency events (i.e., units were motoring). The other Generator Owners were able to identify multiple units in a proper operating state for further analysis and completion of all the Requirements as detailed proposed MOD-027-1. While dependent on the operating state of units during frequency events which are subsequently analyzed, the GSFT-TF believes these activities would constitute compliance with the proposed MOD-027-1 NERC Reliability Standard as currently drafted.

Until the Field Test, there have been few dedicated efforts to verify unit speed load control systems. Because of the large number of generators in SERC, the GSFT-TF determined that an event based methodology, similar to that utilized by WECC, was clearly the most practical course to pursue. However, selection of a tool to perform the simulations to replicate actual frequency excursion events was difficult. Software packages conducive to control system block diagram construction and code generation were evaluated. However, to utilize these packages, each type of speed load control system model to be verified would have to be constructed and tested.

At least one dynamic simulation software package contains a “playback” feature, which forces frequency and voltage signatures that can be manipulated to replicate what was recorded during actual transmission system events. The simulated frequency excursions are then applied to the unit frequency response models so that the resulting MW response predicted by the frequency response models could be compared to the actual captured unit MW response event data. Unfortunately, that capability does not exist for the dynamic simulation software package used by the vast majority of Transmission Planners in SERC.

Despite the absence of a “playback feature”, the tool chosen for this Field Test effort was the dynamic simulation software package utilized in SERC. The GSFT-TF developed a small 3 bus loadflow, with a dominant “Eastern Interconnection” machine and the test machine. Source code altering the mechanical power of the dominant machine was developed to force the dominant machine to slow down relative to 60 hertz and create a simulated transmission system frequency to approximately replicate the actual recorded transmission system frequency. The resulting unit MW versus time output produced by the test machine unit frequency response model was compared to the actual unit MW versus time output captured by the event data. Further details can be found in SERC MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc.

The GSFT-TF volunteer entities investigated multiple models for two separate frequency excursion events. In some cases, good correlation between the event data and model data was not obtained. The field test concluded before issues regarding the poor correlation could be resolved. Once the poor correlations are resolved, the end result will be closer correlation between the models and the actual performance of the installed equipment.

The Field Test was a successful proof of concept exercise. However, the processes would require additional development before becoming a “production grade” activity that would be expected for compliance with an approved NERC Reliability Standard. Following are a list of specific issues that would need to be addressed before it is practical for unit frequency response model verifications be required per an enforceable NERC Reliability Standard:

1) A process would need to be set up to identify frequency excursion events which meet minimum criteria for verifying unit speed load governor systems, and subsequently communicate this information to the appropriate parties.
2) A significant number of units are not equipped with event recording equipment with sufficient resolution, triggering capabilities (if not inherently continuous) and/or data retention. Also, some plants do not have individual recording equipment for each unit (example, CC plants often sum their MW output into one transducer or meter)
3) A tool needs to be developed that can be utilized by the entities responsible for verifying the unit speed load models. While SERC utilized dynamic simulation software predominately used by almost all SERC members with a small loadflow along with flecs code unique to each frequency excursion event. The process was cumbersome and required user expertise in dynamic simulation. It did not exactly replicate the transmission system frequency and the models MW output often had high frequency oscillations associated with numeric instability (note – we were advised by the software vendor to alter the frequency filter, but this resulted in limited positive impact). In summary, the process is not “production grade”.
4) Staged events, at least in the Eastern Interconnection, are impractical. It will probably take significant calendar time before enough events would occur to capture most of the non-exempt units on-line but far enough below maximum power output for governor response to be observed. The GSFT-TF recommends that all units below 75 MVA or interconnected at voltages less than 100 kV should be exempt from the model verification requirements. Also, rigorous configuration control processes should be allowed as a means to demonstrate that validated unit responses are unchanged.

Working through these issues will take considerable time and effort. Therefore, the GSFT-TF recommends that drafting efforts on this standard be delayed until such time as adequate tools be developed and made available.

However, if draft Reliability Standard MOD-027-1 continues through the drafting process and is ultimately successfully balloted, the effective date should be delayed for 2 years, with the requirements phased in over at 20% per year over the next 5 years.

PRC-019-1: Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in PRC-019-1. Five SERC Generator Owners actually performed the activities detailed in the completed SERC Field Test Guidelines. The GSFT-TF believes these activities would constitute compliance with the proposed PRC-019-1 NERC Reliability Standard as currently drafted.

One Generator Owner has been performing these unit coordination studies a number of years. Out of roughly 65 generating units reviewed, only one case of marginal coordination was identified. Prior to the Field Tests, the other entities had limited experience. The other Generator Owners initiated new processes, utilizing the Field Test Guidelines for direction. In all cases, the Generator Owners reported significant startup costs in both manpower and capital costs. Selection of tools, and obtaining equipment limit characteristics from vendors proved to be manpower intensive. No miscoordinations were identified by the other entities participating in this field test. The GSFT-TF estimates this could cost as much as $16 million to meet these requirements for all the applicable generating units in the SERC region. However, even with the high costs the GSFT-TF agrees that this is a beneficial standard.

The GSFT-TF discussed and noted that it may be difficult to obtain start-up test data on older generators, and that re-performing those tests would be a high cost and significant effort. The GSFT-TF agreed that there should be an exemption for older generators. Other GSFT-TF comments, as detailed in the referenced “Redlined” standard, include:

1) In addition to older generators, all units below 75 MVA or interconnected at voltages less than 100 kV should generally be exempt
2) The prime mover limit should be removed as a required plot characteristic – it hardly ever refers to a true physical limit. It is more appropriate to relate this to the MW capability determined in MOD-024.
3) The requirement to plot additional limits that restrict the MW or Mvar capability should be removed as this is an ambiguous requirement
4) The Generator Owner should retain the latest coordination study and provide it to the Compliance Monitor upon request.

The GSFT-TF agrees that this standard should be phased in at 20% per year.

PRC-024-1: Generator Performance during Frequency and Voltage Excursions

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in PRC-024-1. Three SERC entities, consisting of three GOs and two TOs, attempted to perform the activities detailed in the completed SERC Field Test Guidelines.

The task of determining coordination with the SERC draft frequency excursion curve shown in the PRC-024 Field Test Guidelines was a relatively simple task. Coordination of this curve with UFLS relays has been accomplished in past and an ongoing SERC UFLS study. Ignoring tool startup costs, coordination with generator turbine under frequency protective relays was also relatively simple for two of the GOs. The other GO reported that they have plant procedures in place to manually trip the unit if the frequency drops below thresholds which do not coordinate with the SERC draft frequency excursion curve. The GO went on to state that upon further review, they could alter their plant procedures to coordinate with the draft frequency excursion curve without compromising the unit.

The task of determining coordination with the SERC draft LVRT curve was a more daunting task. Plant auxiliary UV relays did not pose a risk of operating for the SERC draft LVRT characteristic. Utilizing steady state techniques with some simplifying assumptions, such as relaxation of steady state Mvar limits, suggested that generator back up impedance relays would not be able to ride through this characteristic. However, one TO utilized dynamic simulations to approximately create the LVRT characteristic through a small bus dynamic case and found that the back up impedance relay would not be expected to operate for the LVRT excursion. The reason why the steady state evaluation produced an incorrect solution was due to the inherent absence of the exciter time constants and exciter ceiling limits.

Based on reviewing the dynamic simulations, the LVRT characteristic should be changed from fault clearing time until one second should be raised from 0.4 to 0.5 per unit. This is required to provide adequate margin from unit transient instability.

The GSFT-TF understands that in order for Transmission Planners to be able to design UF and/or UV safety net schemes, assumptions regarding the UF and LVRT have to be made. Therefore, there is a reliability need to assess the expected ride through capability of units. However, the draft Reliability Standard as written does not address all of the plant systems that could be limiting factors in ride through capability. The GOs have serious concerns regarding the LVRT capability of systems required for operation of generating plants. Coordination of unit protection systems with the LVRT requirements alone will not guarantee the unit will always remain on-line. For example, Boiler Control Systems, systems unique to Nuclear Power Plants, and station service loads will impact ride through capability. The GOs believe that due to the complexity of these systems it is not possible to ensure a generating plant can survive every event. These topics are discussed in more detail in Attachment 6,

The issue of ride through characteristics for generators, especially LVRT, is evolving throughout the industry. The GSFT-TF experience in the field test shows that additional work is required before an effective NERC Reliability Standard can be developed. The GSFT-TF recommends that a process be put in place for additional research into these areas.

ATTACHMENTS

1. **GSFT-TF Documents**
2. **Standard Redlines**
3. **MOD-026 Test Results**
4. **MOD-027 Test Results**
5. **PRC-019 Test Results**
6. **PRC-024 Test Results**

Attachment 1
GSFT-TF Documents

- **SERC MOD-026 Field Test Guideline Rev 1 (1-11-07).doc**
- **SERC MOD-026 Field Test Reporting Form Rev 0 (1-11-07).doc**
- **SERC MOD-027 Field Test Guideline Rev 0 (3-2-07).doc**
- **SERC MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **SERC PRC-019 Field Test Reporting Form Rev 1 (11-2-06).doc**
- **SERC PRC-019 Field Test Guideline Rev 0 (8-28-06).doc**
- **SERC PRC-024 Field Test Guidelines Rev 0 (3-2-07).doc**
- **SERC PRC-024 GO Field Test Reporting Form Draft 0 (3-13-07).doc**
- **SERC PRC-024 TO Field Test Reporting Form Draft 0 (3-13-07).doc**

SERC Field Test Guidelines

Verification of Models and Data for Generator Excitation System Functions

NERC Reliability Standard MOD-026

SERC Reliability Corporation

Revision History

Revision	Date	Comments
0	October 10, 2006	GSFT-TF finalized SERC MOD-026-1 Guideline for Field Test purposes.
1	January 11, 2007	Revised Attachment 2

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and the Regional Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-026.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-026.

Effective Dates:

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-026.

Table of Contents

I. Introduction/ Purpose 4
II. Definitions 4
III. Requirements/Expectations 5
A. Generator Exemption Criteria [*Ref.MOD-026, R1.1*] 5
B. Sister Unit/Equipment Validation Guidelines 6
C. Configuration Controls 6
D. Excitation System Classification: 7
E. Regulator and Excitation Control Systems 8
1. General Requirements *[Ref.MOD-026, R1.4.2]* 8
2. Specific Requirements *[Ref.MOD-026, R1.2]* 8
F. Power System Stabilizers 11
1. General Requirements *[Ref.MOD-026, R1.4.6]* 11
2. Specific Requirements *[Ref.MOD-026, R1.2]* 11
G. Excitation Limit Controls 12
1. General Requirements *[Ref.MOD-026, R1.3]* 12
2. Specific Requirements *[Ref.MOD-026, R1.2 & R1.4.3]* 12

List of Attachments

Attachment 1: NERC Reliability Standard MOD-026
Attachment 2: Excitation System Questionnaire

I. Introduction/ Purpose

In order to effectively evaluate the electric system's performance, the accuracy of data for the interconnected transmission network and the associated generating equipment is critical. Accordingly, valid data reflecting generator excitation systems are essential for performing planning and operating studies to assess or evaluate the reliability of the electric system.

This SERC field test guideline for the NERC Reliability Standards MOD-026 is intended to:

1) Provide guidance for SERC Generator Owners/Operators to address verification of generator excitation system, power system stabilizers models, and excitation limit controls.
2) Document the GSFT-TF recommended exemption criteria and sister unit philosophy.
3) Document the GSFT-TF recommended Configuration Controls.

II. Definitions

1. **Confirm (–ed, –ation) –** To assure that plant or equipment conditions (including control settings) that would impact previously provided data has not changed.

2. **Exempt Generation –** Generator(s) that meets the exemption criteria for a particular Validation/test requirement.

3. **Validate (-dated, -dation)** – To establish the accuracy of data used to model electrical equipment. Validation may be achieved through simulation, operating data, field readings, engineering evaluations or reviews, use of manufacturer data, commissioning data, performance tracking, and/or testing where appropriate.

4. **Verify (Verification)** – To establish through Validation or Confirmation.

5. **Standard Model (or Model) –** A model included with the Power System Simulator, Power Technologies, Inc. (PSS/E) dynamic simulation software. Many Institute of Electrical and Electronics Engineers, Inc. (IEEE) models are included in the standard PSS/E models. Complete model information includes both the name of the Standard Model and the value of each parameter.

III. Requirements/Expectations

A. Generator Exemption Criteria [*Ref.MOD-026, R1.1*]

In order to maximize the efficiency of generator testing, it is prudent to exempt generators that are believed to have less significant impact on the reliability of the bulk electric system from data Validation requirements. The exemption criteria specified by these guidelines are based on both the operating voltage of the bulk power system to which the generator is interconnected, and the MVA rating of the generator. When referring to the MVA rating of the generator, at facilities where multiple machines and/or prime movers are required for normal unit operation, the MVA rating refers to the total MVA capacity of the facility. Examples of this include combined cycle or cross compound units.

As documented in the NERC Glossary of Terms, the NERC Board of Trustees approved a definition for the bulk electric system on February 8, 2005 as follows:

> "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition."

Therefore, for generators interconnected to a power system operated at a voltage of less than 100 kV, Validation is not required. Inasmuch as possible, models and model parameters should be based on the most accurate information available from sources such as the manufacturer, calibration and maintenance records and field inspection (i.e., estimated parameters).

Generators with a nameplate rating less than or equal to 75 MVA or that are not connected to the bulk power system are exempt.

Table 1 summarizes the Generator Exemption Criteria.

Generator Interconnected kV or MVA Size	Validated Models & Data Required
< 100 kV	No
≥ 100kV & ≤ 75 MVA	No
≥100kV & > 75 MVA	Yes

Table 1: Generator Exemption Criteria

B. Sister Unit/Equipment Validation Guidelines

Some units have equipment with the same characteristics such that they respond the same as equipment of other units. If it can be demonstrated that the units, equipment, or systems have identical designs, identical major components and identical significant control system settings, then the units can be considered sisters in regard to that equipment or system. In those situations, an assumption can be made for a sister unit by Validating the excitation system (and PSS system as appropriate) model for one (sample) unit. Equipment or systems that do not impact the equipment or system to be Validated need not be identical. Units that are sisters in one regard may not be sisters for other equipment or systems to be Validated. Documentation must exist to demonstrate that the information about the sample unit can be applied to a sister unit. In future Validations, a different sister unit shall be selected to eventually verify that the sister approach was valid.

C. Configuration Controls

The Generator Owner shall implement a program intended to ensure the condition of the excitation controls (Automatic Voltage Regulator, Limiters, and Power System Stabilizer) remains consistent with the state of the equipment when the latest model Verification was performed. This will normally be performed during a major generator outage, or when setting changes are implemented. [Ref.MOD-026, R1.4.6]

There are several programmatic alternatives that are considered adequate for assuring the generator excitation system models accurately reflect the response of the field equipment. The alternatives are:

1. Periodically repeating the baseline testing and simulation comparisons to assure the model parameters submitted for dynamic simulations are accurate.
2. With the appropriate data collection equipment and excitation system modeling expertise available, the generator owner may want to Validate the model by alternate means.
3. If analog control equipment owners regularly calibrate their controls and have documented excitation system parameters at the time of the baseline test, then future calibration activities can be conducted with the goal of maintaining excitation system parameters in the as-modeled state. This assures and documents that the excitation system modeling parameters are still consistent with the Validated baseline model parameters.
4. For digital excitation systems , once baseline parameters are established through testing, future Validation activities shall consist of ensuring any components that may drift (such as A/D converters) are properly calibrated and ensuring the control system parameters have not changed from the baseline data.
5. In general, hybrid excitation systems (excitation systems that contain both analog and digital subsystems), should be treated as analog control systems.

D. Excitation System Classification:

The generator owner shall provide the Planning Authority and/or Transmission Planner the following excitation system classification information (see Attachment 2) [*Ref.MOD-026, R1.4.1*]:

1. Manufacturer and Type of Excitation System. Examples of excitation system types are static, brushless, alternator rectifier, motor driven dc exciters, etc
2. Manufacturer and Type of Voltage Regulator.

E. Regulator and Excitation Control Systems

1. General Requirements *[Ref.MOD-026, R1.4.2]*

a) The Generator Owner shall provide an appropriate automatic voltage regulator and excitation system Standard Model and associated parameters. The Transmission Planner shall provide assistance in selection and Validation of this Standard Excitation Model[1].

b) The Generator Owner shall provide reactive current or line drop compensation settings where applicable. *[Ref.MOD-026, R1.4.4]*

c) The Generator Owner shall provide open circuit step test data necessary for Validation of the model for the excitation control system.

d) The Transmission Planner will perform a simulation of the open circuit test using the modeling data provided in sections a, b, and c above to verify the generator excitation system model.

e) Due to nuclear licensing requirements and concerns, Transmission Planners and Generator Owners shall coordinate any required studies, assessment, and / or testing of the generator excitation systems that could adversely impact the capacity and/or the capability of the nuclear plant off-site sources and nuclear plant safety.

2. Specific Requirements *[Ref.MOD-026, R1.2]*

a) Validation Process
Adequate Validation requires a baseline model to be established in conjunction with an Open Circuit Step Response (OCSR) test. (Note: Data from an OCSR test itself does not constitute the model, but can be used to adjust the model parameters until the simulation results closely match the OCSR response.) This test consists of collecting data (for data points, see below) on the generator performance during transients when a step in the voltage reference is introduced.

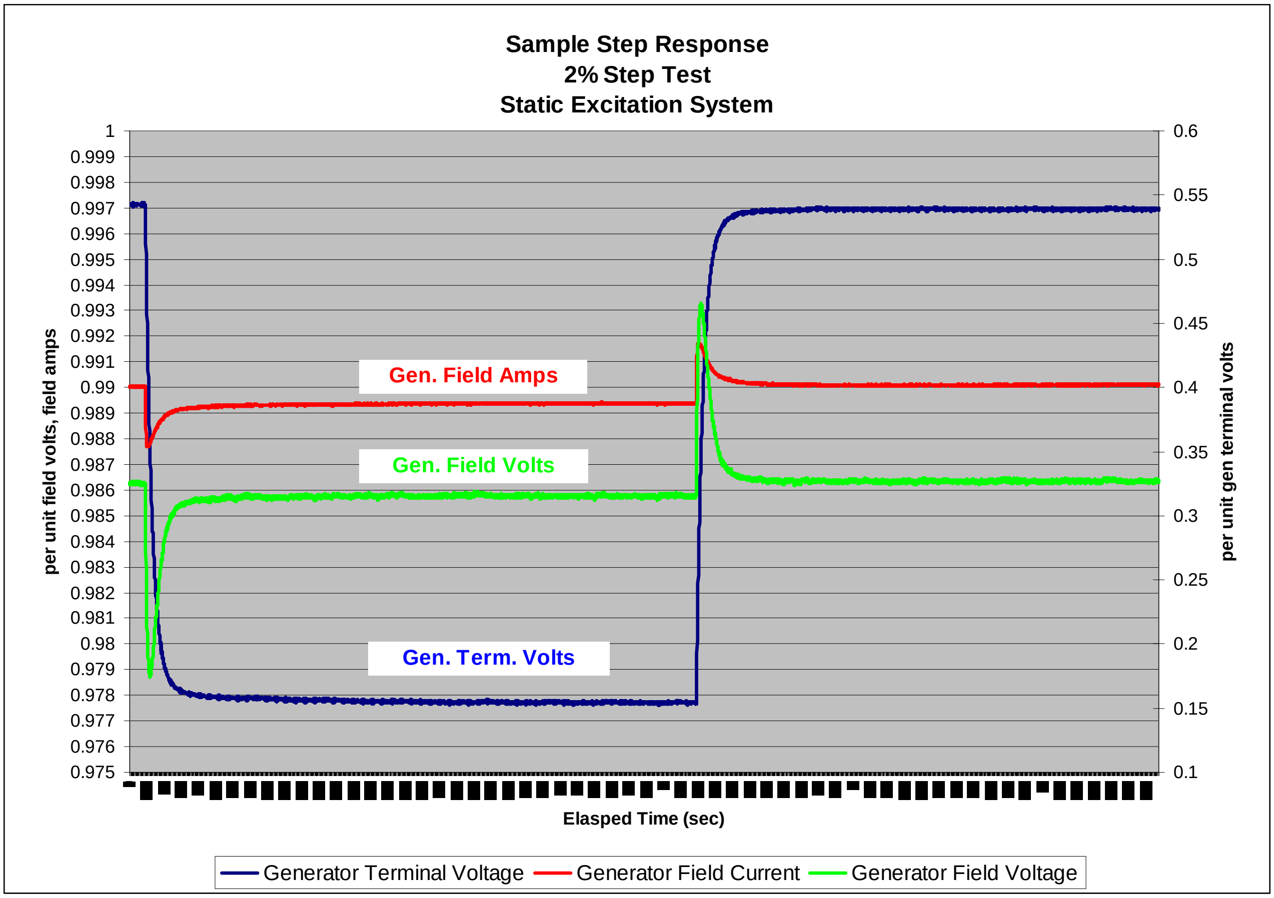
[1] Many times, dynamic simulation software manufacturers wait until a model is approved by IEEE before including it within the library of models provided with the software. Therefore, there can be a significant time lapse between installation/use of something that requires a model and the availability of a Standard Model. Until such time as new models are added to the Transmission Planners' model library, a Standard Model that most closely approximates the actual response shall be used. User Defined Models are usually complicated and troublesome to incorporate into the regional and interregional dynamics databases, and therefore they shall only be used in extraordinary situations

Good correlation between the model and the OCSR test must be achieved. Otherwise, the model along with other variables that affect exciter response must be re-examined.

b) Data Points Required for Validation Tests *[Ref.MOD-026, R1.4.5]*
The following data points shall be monitored for Validation. If signal transducer outputs are used for data collection, any time lags introduced by the transducer must be accounted for in the model Validation process. Otherwise, the response of the transducer output may be inappropriate for model Validation. The test parameters are:

1.) Generator Voltage
2.) Field Voltage (Generator and/or Exciter as appropriate)
3.) Field Current (Generator and/or Exciter as appropriate)
4.) Step input (for voltage step test)

Note, the magnitude of the step input (generally expressed as a percentage of the generator voltage) shall be stated, but shall be no less than 1%. See sample test data below. Some recording equipment allows both graphical and tabular data formats. These data collection systems are preferred since one can visually see the results and can use the tabular data for comparison with simulated results to aid in the validation process.


Sample Step Response
2% Step Test
Static Excitation System
per unit field volts, field amps
1
0.999
0.998
0.997
0.996
0.995
0.994
0.993
0.992
0.991
0.99
0.989
0.988
0.987
0.986
0.985
0.984
0.983
0.982
0.981
0.98
0.979
0.978
0.977
0.976
0.975
per unit gen terminal volts
0.6
0.55
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
Gen. Field Amps
Gen. Field Volts
Gen. Term. Volts
Elasped Time (sec)
Generator Terminal Voltage
Generator Field Current
Generator Field Voltage

F. Power System Stabilizers

1. General Requirements *[Ref.MOD-026, R1.4.6]*

All units that have commissioned Power System Stabilizers (PSS) must submit a Validated Standard Model. The Standard Model will normally be Confirmed during a major outage, or when setting changes are implemented. *[Ref.MOD-026, R1.3]*

2. Specific Requirements *[Ref.MOD-026, R1.2]*

a) Units commissioning new PSSs will supply the Transmission Planner applicable test results provided upon commissioning. This includes results of the Gain Margin test, Phase Compensation test, and on-line step in voltage tests with and without the PSS in service.

b) Units that have previously commissioned PSSs will supply the Transmission Planner applicable test results provided from the initial commissioning, if available, including the results of the Gain Margin test, Phase Compensation test, and on-line step in voltage tests with and without the PSS in service. If the aforementioned tests are not available, the Transmission Planner may grant the Generator Owner the option of providing a PSS tuning study report along with field verification of the exciter and PSS settings.

c) Where appropriate, the Standard Model data can be described by block diagrams and/or tables, based on standard IEEE or PSS/E type models.

d) The Phase Compensation Test must include a gain and phase shift Bode plot for the excitation system with and without the stabilizer. Each Bode plot must be formatted as follows:

1) Semi-log type chart
2) Gain magnitude expressed in decibels
3) Phase shift expressed in degrees
4) Frequency expressed in Hertz, typically 0.01 – 5.0 Hz log scale

G. Excitation Limit Controls

1. General Requirements *[Ref.MOD-026, R1.3]*

a) Data concerning excitation limit controls must be submitted for all units. Updated data must be submitted to the Planning Authority and/or Transmission Planner each time changes are made that could affect the limits (such as upgrades and replacements). This data shall be Confirmed during a major generator outage, or when setting changes are implemented.

b) For new or refurbished systems, design data obtained from the vendor and submitted at the time of requisition is sufficient until such time as more accurate data (from commissioning/acceptance testing) can be obtained and submitted to the Transmission Planner.

2. Specific Requirements *[Ref.MOD-026, R1.2 & R1.4.3]*

a) Verification of setpoints may be performed for most of the regulator systems with the generator shutdown by providing simulated inputs (such as PT and CT) of the appropriate magnitude and phase angle and assuring that the regulator responds appropriately when the limit is reached.

b) Underexcition Limiter setpoints could also be checked by lowering excitation with the unit on line until the limiter prevents any further decrease in excitation.

c) If data is retrievable, calibration or maintenance data such as field measurements may be used to calculate limiter characteristics instead of a separate test.

Attachment 1

NERC Reliability Standard MOD-026

A. Introduction

1. **Title:** **Verification of Models and Data for Generator Excitation System Functions**
2. **Number:** MOD-026-1
3. **Purpose:** To ensure accurate information on generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) is available for models used to assess Bulk Electric System reliability.
4. **Applicability**
   - **4.1.** Regional Reliability Organization.
   - **4.2.** Generator Owner.
5. **Proposed Effective Date:** To be determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of models and data associated with generator excitation system functions including voltage regulator controls, limiters, compensators, and power system stabilizers. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.3. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.

R1.4. Information to be reported related to generator excitation system functions:

R1.4.1. Verified manufacturer and type of excitation system/voltage regulator control system (for example, static, brushless, rotating, etc.).

R1.4.2. Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits.

R1.4.3. Verified static set points for under and over excitation limiters.

R1.4.4. Verified line drop compensator settings.

R1.4.5. Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

R1.4.6. Verified model for each power system stabilizer with associated gains, time constants, and limits.

R1.4.7. Confirmation that the verification was conducted with the voltage regulator in the automatic voltage control mode

R1.4.8. Method of verification used.

R1.4.9. Date of verification.

R2. The Regional Reliability Organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its models and data associated with generator excitation system functions per MOD-026 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for the verification and reporting of models and data associated with its generator excitation system functions in accordance with MOD-026 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure for verification and reporting of generator excitation system data, and any revisions to that procedure were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with its generator excitation system functions, consistent with the Regional Reliability Organization procedure.

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name: ______________________________________**
2. **Company: ____**
3. **Date: ____**
4. **Submitter: ______________________________________**
5. **Phone No. _______________________________________**

1. Exciter Information:

Manufacturer: ____________________________________

Type of Excitation System:

☐ Static
☐ Brushless
☐ Alternator Rectifier
☐ Motor Driven dc exciter
☐ Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: _________________________________

Type of Voltage Regulator:

☐ Analog
☐ Digital
☐ Other(describe)
☐

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes______ No____

If the answer is yes,

Manufacturer: _________________________________

Type of PSS:

☐ Single input (delta speed/frequency type)
☐ Dual input (integral of accelerating power)
☐ Other(describe)
☐

Attachment 2

Reporting Form

Excitation Systems Controls

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2.

6. Provide the data required in III.G.2 on Excitation Limit Controls.

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : ________ Hours
   - Setup of Test Equipment: ________ Hours
   - Time to Prepare Unit for Test: ________ Hours
   - Performance of Test and Data Collection: ________ Hours
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? ________ Hours
3. Was a good correlation between the exciter model and the OCSR test obtained? (Yes or No)

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? ________________________
5. List any material costs associated with this testing.

   ____
   ____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (Yes or No). If no, please attach additional information as appropriate.
7. Please list any suggested changes to the guideline?

   ____
   ____
   ____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026).
9. Name of the person completing the form:________________ Phone Number_________ Company Name_______________

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

SERC Field Test Guideline

Verification of Generator Unit Frequency Response

NERC Draft Reliability Standard MOD-027

SERC Reliability Corporation

Revision History

Revision	Date	Comments
0	March 2, 2007	GSFT-TF finalized SERC MOD-027-1 Guideline for Field Test purposes.

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and the Regional Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-027.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-027.

Effective Dates – Not Applicable:

Table of Contents

I. Introduction 4
II. Definitions 4
III. Requirements/Expectations 5
   A. Generator Exemption Criteria [Ref.MOD-027, R1.2] 5
   B. Sister Unit/Equipment Validation Guidelines 6
   C. Configuration Controls 7
   D. Turbine and Governor (Speed/Load) Controls [Ref. MOD-027, R1] 8
      1. General Requirements 8
      2. Specific Requirements 9

List of Attachments

Attachment 1: Draft NERC Reliability Standard MOD-027
Attachment 2: Sample Reporting Form: Turbine and Governor (Speed/Load) Controls Questionnaire
Attachment 3: Definitions of Unit Frequency Response

I. Introduction

In order to effectively evaluate the electric system's performance, the accuracy of data for the interconnected transmission network and the associated generating equipment is critical. This document addresses one such item, generating unit frequency response and associated model data. For dynamic planning and operating studies with a time frame of 0 to 60 seconds, unit frequency response of hydro and conventional fossil steam generating units is primarily influenced by the turbine governor system. Thus, valid models for these type units should focus on the governor system. For combustion turbine based generation (CTs and Combined Cycle), unit frequency response for 0 to 60 seconds can be influenced by both the governor system, if active for frequency control, and other plant control systems such as combustion turbine firing temperature controls, etc. Thus, the development of valid models for these units may require additional control functions. Nuclear generating units typically do not provide a frequency response since their governor systems are generally inactive or insensitive regarding frequency control. If this is the case, the development of valid models for those units is not necessary.

This SERC field test guideline for the NERC Reliability Standards MOD-027 is intended to:

1) Provide guidance for SERC Transmission Planners and Generator Owners/Operators to address verification of generator unit frequency response.
2) Document the GSFT-TF recommended exemption criteria and sister unit philosophy.
3) Document the GSFT-TF recommended Configuration Controls.

After this field test has been completed, and if MOD-027 Reliability Standard is approved and implemented, the GSFT-TF recommends that SERC develop a regional procedure identifying future events for which data should be collected and evaluated by SERC members.

II. Definitions

1. **Confirm (–ed, –ation) –** To assure that plant or equipment conditions (including control settings) that would impact previously provided data has not changed.

2. **Exempt Generation –** Generator(s) that meets the exemption criteria for a particular Validation/test requirement.

3. **Validate (-dated, -dation)** – To establish the accuracy of data used to model electrical equipment. Validation may be achieved through simulation,

operating data, field readings, engineering evaluations or reviews, use of manufacturer data, commissioning data, performance tracking, and/or testing where appropriate.

4. **Verify (Verification)** – To establish through Validation or Confirmation.

5. **Standard Model (or Model) –** A model included with the Power System Simulator, Power Technologies, Inc. (PSS/E) dynamic simulation software. Many Institute of Electrical and Electronics Engineers, Inc. (IEEE) models are included in the standard PSS/E models. Complete model information includes both the name of the Standard Model and the value of each parameter.

III. Requirements/Expectations

A. Generator Exemption Criteria [Ref.MOD-027, R1.2]

In order to maximize the use of resources, it is prudent to exempt generators that are believed to have less significant impact on the reliability of the bulk electric system from data Validation requirements. The exemption criteria specified by these guidelines are based on both the operating voltage of the bulk power system to which the generator is interconnected, and the MVA rating of the generator. When referring to the MVA rating of the generator, at facilities where multiple machines and/or prime movers are required for normal unit operation, the MVA rating refers to the total MVA capacity of the facility. Examples of this include combined cycle or cross compound units.

As documented in the NERC Glossary of Terms, the NERC Board of Trustees approved a definition for the bulk electric system on February 8, 2005 as follows:

> "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition."

Therefore, for generators interconnected to a power system operated at a voltage of less than 100 kV, Validation is not required. Inasmuch as possible, models and model parameters should be based on the most accurate information available from sources such as the manufacturer, calibration and maintenance records, field inspection (i.e., estimated parameters), and event data.

Generators with a nameplate rating less than or equal to 75 MVA or that are not connected to the bulk power system are exempt. Table 1 summarizes the Generator Exemption Criteria.

Table 1:

Generator Interconnected kV or MVA Size	Validated Models & Data Required
< 100 kV	No
≥ 100kV & ≤ 75 MVA	No
≥100kV & > 75 MVA	Yes

Generator Exemption Criteria

B. Sister Unit/Equipment Validation Guidelines

Some units have equipment with the same characteristics such that they respond the same as equipment of other units. If it can be demonstrated that the units, equipment, or systems have identical designs, identical major components and identical significant control system settings, then the units can be considered sisters in regard to that equipment or system. In those situations, an assumption can be made for a sister unit by Validating the unit frequency response model for one (sample) unit. Equipment or systems that do not impact the equipment or system to be Validated need not be identical. Units that are sisters in one regard may not be sisters for other equipment or systems to be Validated. Documentation must exist to demonstrate that the information about the sample unit can be applied to a sister unit. In future Validations, a different sister unit shall be selected to eventually verify that the sister approach was valid.

C. Configuration Controls

The Generator Owner shall implement a program intended to insure the condition of the unit frequency response system (speed / load control system) remains consistent with the state of the equipment when the latest model Validation was performed. This will normally be performed during a major generator outage, or when setting changes are implemented. [Ref.MOD-027, R1.3]

Turbine-Generator speed/load governor systems consist of:

1) a speed signal from the TG
2) a speed load governor controller
3) mechanical (usually hydraulic) actuators and valves (or gates on hydro units)

In general, the speed signal and mechanical portion of the system are not modified unless the overall governor system is being modified. Thus, Configuration Controls do not apply to these two subsystems. The speed load governor controller may vary widely between units due to vintage, retrofit or component modification and thus is the primary focus in the Configuration Controls. The following addresses the key aspects of a Configuration Controls program for the speed load governor controller portion of the system. In cases where the controller is being replaced, the speed/load governor system should be treated like a new governor.

1. Periodically repeating the event based model Validation described in Section D.2 (post-mortem simulation of specific event(s) using dynamics models to validate turbine governor and associated control systems parameters) to assure the existing model parameters for dynamic simulations are accurate.

2. Due to their design, the response of a Mechanical Hydraulic Control (MHC) system is not easily adjustable and thus if properly maintained (replacement of deteriorated components), it is not subject to appreciable performance changes. Thus, no specific Configuration Controls process is necessary.

3. For analog based governor controllers (Electro Hydraulic Control - EHC systems), the Configuration Controls process should consist of a maintenance program that includes regular calibration of the controller to

conform to baseline data (typically previous calibration data) that was used in the previously governor model Validation process described in Section D.2

4. For digital based governor controllers (Digital Electro Hydraulic - DEH systems), the Configuration Controls process should consist of a maintenance program that includes regular calibration of any components that are subject to drift (such as A/D converters) and verification that the configuration files are the same as those utilized in the original Validation activities.

These activities should assure and document that the unit frequency response system modeling parameters are still consistent with the validated baseline model parameters.

D. Turbine and Governor (Speed/Load) Controls [Ref. MOD-027, R1]

1. General Requirements

a) Generator Owners will submit to their Transmission Planner an appropriate speed/load control system Standard Model with associated parameters (based on the most accurate information available from sources such as the manufacturer, calibration and maintenance records, field inspection, operating data and engineering evaluations or reviews) and the Attachment 2 reporting form for each generating unit. The Generator Owner and the Transmission Planner may need to coordinate to determine which Standard Model to use. (Ref.MOD-027, R1.5.1)

b) As detailed in D.2., an event based approach to Validate generator unit frequency response will be utilized.

c) For each new or modified speed/load control system, a Standard Model (based on as-built parameter information available from the vendor) must be submitted in addition to the Attachment 2 questionnaire. The model based on this design data is sufficient until more accurate data (from event analysis or commissioning/acceptance testing) can be obtained and submitted to the Transmission Planner. The Generator Owner and the Transmission Planner may need to coordinate to determine which Standard Model applies and/or what data should be provided. (Ref.MOD-027, R1.4)

d) If there are typical operating modes that have different control parameters, a model must be provided for each mode.

e) Standard Models and/or parameters must be Validated each time changes are made that could affect the model such as upgrades and replacements or Confirmed at least every five years. (Ref.MOD-027, R1.4)

f) SERC shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 days of approval. (Ref.MOD-027, R2)

g) The Generator Owner and Transmission Planners shall follow the SERC procedure for verifying and reporting its generator unit frequency response. (Ref.MOD-027, R3)

2. Specific Requirements

An event based approach will be utilized to Validate unit frequency response for each applicable generator. Generator response data for specific frequency excursion event(s) will be compared to the unit frequency response predicted by the Standard Models. Validation of the unit frequency response system is achieved by adjusting (if necessary) the turbine governor and associated control systems parameters[1] in the Standard Model until good correlation with the captured event(s) data is obtained. [Ref.MOD-027, R1.3]

a) Speed/load control system response must be Validated with underfrequency event data. In order for event data to be suitable for Validation, the data must

- Record generator electric power and local system frequency
- Record a frequency drop to 59.96 Hz or below (resolution 0.01 Hz)
- Have a generator power resolution of 1% of the generator Continuous Capability
- Record data every 4 to 6 seconds, or more frequently
- Record data for at least 60 seconds, or more depending on the timeframe of the response

b) Generator event data required is unit MW output versus time. This data may be obtained from SCADA systems, data loggers, excitation/governor event capturing systems, dedicated monitoring systems or test instrumentation.

[1] As reference see Pereira, Undrill, Kosterev, Davies and Patterson, “A New Thermal Governor Modeling Approach in the WECC,” IEEE Trans. Power Syst., vol 18, pp 819-829, May 2003 and other documents located on the WECC website for the Modeling and Validation Work Group (MVWG) at http://www.wecc.biz/committees/PCC/TSS/MVWG/documents/index.html

c) PSS/E dynamic simulation software will be used by SERC for the NERC Field Test activity of Validating the generator's speed/load control models:

1. A loadflow consisting of a large (MVA) unit representing Eastern Interconnection (EI), a large EI load, the unit whose speed/load model is to be Validated, and any other transmission system elements required to replicate the event will be modeled. The loadflow is expected to have ten or less buses.
2. Transmission system frequency versus time event data will be examined as part of the validation process
3. After creating the dynamic "snap" but before compiling and linking the dynamics executable, "flecs" code will be inserted in the "conec" file. The code will alter the mechanical power of the large EI machine. The result is that the large EI machine will speed up or slow down accordingly, thus changing system frequency to reasonably match the event data.
4. The resulting unit MW versus time output produced by the model will be compared to the actual unit MW versus time output captured by the event data. If good correlation[2] is obtained, Validation of the model is complete. If good correlation is not obtained, the following courses of action should be considered:
   i. Modify the parameters of the unit's existing speed/load model and repeat the Validation process.
   ii. A new model with new parameters could be developed.
   iii. The Generator Owner could investigate why good correlation was not obtained, which could result in refining the unit's frequency response controls
5. Care should be taken to consider more than one frequency excursion event before implementing an updated model into the dynamics database.

d) When Validating the generator power output response of an event simulation with actual recorded event data, the response time to be modeled should be 60 seconds, regardless of unit type. If compromises have to be made in the selection of model parameters, there should be emphasis on selecting parameters that best replicate the generator power output response during the first 30 seconds of the event. (Ref.MOD-027, R1.1).

e) It is recognized by the GSFT-TF that other stand alone software programs could be used to replicate a transmission system frequency

[2] As part of the field test activities efforts will be made to quantify "good correlation."

excursion and subsequently Validate generator unit speed/load control models. The GSFT-TF investigated and determined that PSLF ™, EMTP ™, and MAT LAB ™ software programs could be used for this activity. Therefore, upon the successful ballot and NERC B.O.T and FERC adoption of draft NERC Reliability Standard MOD-027, the GSFT-TF would advise SERC that the aforementioned and other commercially available software tools could be utilized to fulfill the applicable NERC requirements.

f) Reporting

A record of the most recent Validation including information specified in NERC Reliability Standard MOD-027-1 R1.5.1 – R.1.5.4 on each generator shall be maintained by the Validating party and reported to SERC or NERC within 30 days of the request. (Ref.MOD-027, R1.4, R1.5.1 - R1.5.4)

g) Examples

Attachment 3 refers to several types of turbine - governor controllers.

Attachment 1

A. Introduction

1. **Title:** **Verification of Generator Unit Frequency Response**
2. **Number:** MOD-027-1
3. **Purpose:** To provide verification of generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies.
4. **Applicability**
   - **4.1.** Regional Reliability Organization.
   - **4.2.** Generator Owner.
5. **Proposed Effective Date:** To be Determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator unit frequency response. These procedures shall include the following:

- **R1.1.** Response time to be modeled, e.g. up to 30 seconds for steam units, up to 45 seconds for hydro units, etc.
- **R1.2.** Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.
- **R1.3.** Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.
- **R1.4.** Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.
- **R1.5.** Information to be reported related to generator unit frequency response:
  - **R1.5.1.** Verified manufacturer and type of speed governor controls.
  - **R1.5.2.** Verified model for each speed governor control with any associated deadband, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.).
  - **R1.5.3.** Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response).
  - **R1.5.4.** Method of verification and conditions of the verification including status of controls.

R2. The Regional Reliability Organization shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying and reporting its generator unit frequency response per MOD-027 R1.

Attachment 1

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for verifying and reporting generator unit frequency response in accordance with MOD-027 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure, and any revisions to that procedure, for verification and reporting generator unit frequency response was provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with generator unit frequency response, consistent with the Regional Reliability Organization procedure.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name:** ____________________________________
2. **Company:** ______________________________________
3. **Date:** ____
4. **Submitter:** _____________________________________
5. **Phone No.** _____________________________________

Governor Information:

Identify general type of governor control:

- ☐ Mechanical hydraulic (MHC)
- ☐ Analog electro-hydraulic (EHC)
- ☐ Digital electro-hydraulic (DEH)
- ☐ _________________________

Check type of governor model submitted:

- ☐ PTI Standard Model with As built parameters
- ☐ PTI Standard Model with Estimated Parameters
- ☐ PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ____________

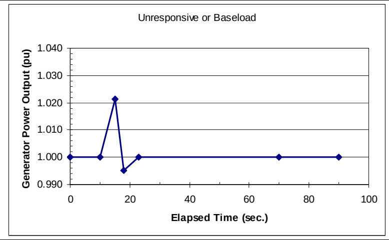
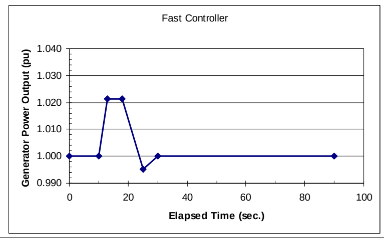
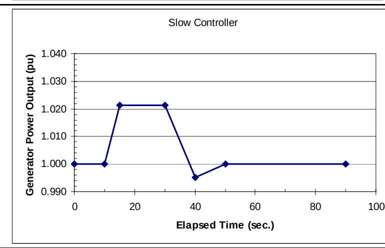
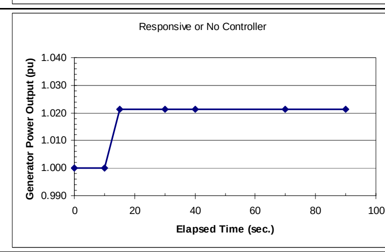
Attachment 3

Definitions of Unit Frequency Response

Steam units may operate in several modes, but for modeling these three will be considered:

Baseload –	Operating at or near maximum output
Setpoint Control –	Operating such that other controls will override automatic action of the governor. Typically the setpoint is related to load and temperature limits.
Responsive –	Operating with typical governor control without other automatic override controls.

Based on the above information and the diagram below, the type of turbine – governor response for thermal units is defined:

<table>
<tr><td></td><td>Thermal</td><td></td><td>Examples†</td></tr>
<tr><td></td><td>Type UC</td><td>Unresponsive, baseload unit (very quickly returns to near baseload after an initial response)</td><td>
</td></tr>
<tr><td></td><td>Type FC</td><td>Fast controller, shorter response (quickly returns to near baseload)</td><td>
</td></tr>
<tr><td></td><td>Type SC</td><td>Slow controller, longer response (responds for a short time, then returns to near baseload)</td><td>
</td></tr>
<tr><td></td><td>Type NC</td><td>No controller, responsive</td><td>
</td></tr>
</table>

† Just to illustrate what each type may look like, some example charts are given. The event is assumed to occur at 10 seconds and a hypothetical change in generator output is depicted.

Gas turbine units are divided into two categories:

	Gas	
	Type GL	with load controller
	Type GN	no load controller

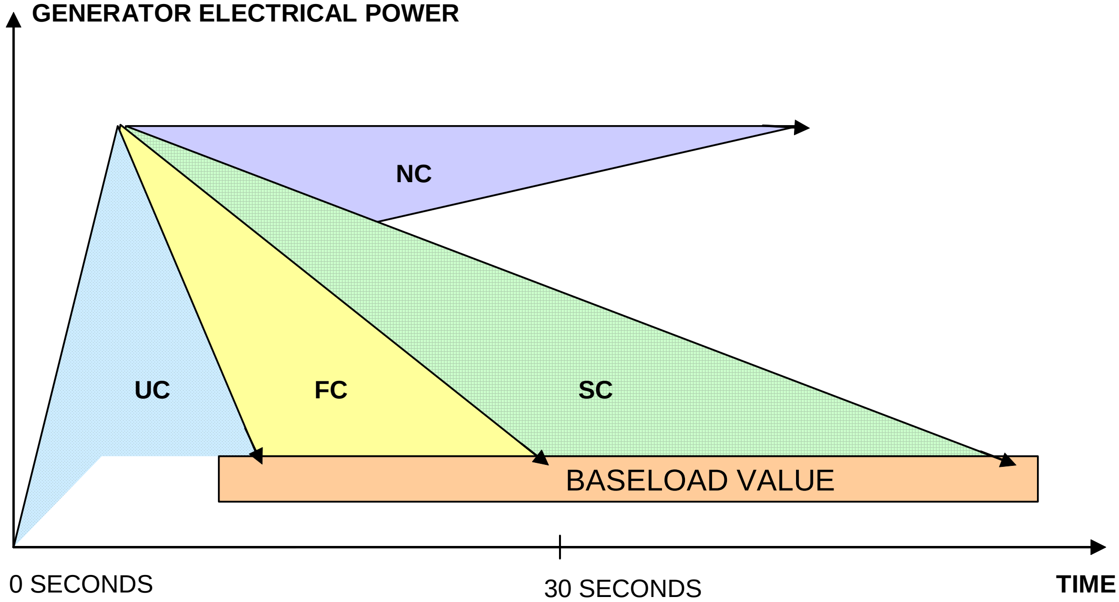


Figure A3-1, General characteristics of each type of turbine – governor response

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No)
   - If yes, what is the maintenance interval? (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No)
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No)

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? (hours)
   - How long did it take to set up the model to simulate this event? (hours)
   - How long did it take to compare the generator output data to the model? (hours)
   - Did the model parameters or type need to be changed?

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study.
5. Please list any suggested changes to the guideline?
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Phone Number:

   Company Name:

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

SERC Field Test Guideline

Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

NERC Reliability Standard PRC-019

SERC
SERC Reliability Corporation

Revision History

Revision	Date	Comments
0	August 28, 2006	GSFT-TF finalized SERC PRC-019-1 Guideline for Field Test purposes.

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and the Regional Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-019.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-019.

Effective Dates:

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-019.

Table of Contents

I. Introduction 4
II. Definitions 4
III. Requirements/Expectations 5
A. Generator Exemption Criteria 5
B. Sister Unit/Equipment Verification Guidelines 6
C. Requirements 6

List of Attachments

Attachment 1: NERC Reliability Standard MOD-019
Attachment 2: Example – Over Excitation Capability Coordination
Attachment 3: Example – Generator Field Over Excitation Limiter/Protection Coordination
Attachment 4: Example – Volts/Hertz Coordination
Attachment 5: Example – Under Excitation Capability Coordination
Attachment 6: Example – Circle and Radius Equations

I. Introduction

This SERC field test guideline for the NERC Reliability Standards PRC-019 is intended to:

1) Provide guidance for SERC Generator Owners/Operators in conducting studies to show coordination of generator voltage regulator controls with unit capabilities and protection as specified by the NERC Reliability Standards (Section IIIA).
2) Document the GSFT-TF recommended exemption criteria (Section IIIA) and sister unit philosophy (Section IIIB).

II. Definitions

1. **Generator Capability Curve –**A graphical presentation of data that illustrates the thermal limits of the combined real and reactive power capability of the generator at the specified terminal voltage.
2. **Additional Definitions to be added as needed.**

III. Requirements/Expectations

A. **Generator Exemption Criteria** [*Ref.PRC-019, R2.*]

In order to maximize the use of resources, it is prudent to exempt generators that are believed to have less significant impact on the reliability of the bulk electric system from maintaining rigorous documentation of generator control and protective relay coordination study results. The exemption criteria specified by this guideline are based on both the operating voltage of the bulk power system to which the generator is interconnected, and the MVA rating of the generator. When referring to the MVA rating of the generator, at facilities where multiple machines and/or prime movers are required for normal unit operation, the MVA rating refers to the total MVA capacity of the facility. Examples of this include combined cycle or cross compound units.

As documented in the NERC Glossary of Terms, the NERC Board of Trustees approved a definition for the bulk electric system on February 8, 2005 as follows:

> "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition."

Therefore, for generators interconnected to a power system operated at a voltage of less than 100 kV, a documented study demonstrating the coordination of generator voltage regulator controls with unit capabilities and protection is not required.

Generators with a nameplate rating less than or equal to 75 MVA or that are not connected to the bulk power system are exempt.

Table 1 summarizes the Generator Exemption Criteria.

Generator Interconnected kV or MVA Size	Study Documentation of Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection Required
< 100 kV	No
> 100kV & ≤ 75 MVA	No
>100kV & > 75 MVA	Yes

Table 1: Generation Exemption Criteria

B. Sister Unit/Equipment Verification Guidelines

If it can be demonstrated that the generators, voltage regulator and exciters along with their control and protection system equipment and settings are all identical, then the units can be considered sisters units. In those situations, an assumption can be made for a sister unit by coordinating the generator voltage regulator controls with unit capabilities and protection for one (sample) unit. Documentation must exist to demonstrate that the information about the sample unit can be applied to a sister unit.

C. Requirements [*Ref. PRC-019, R2.1*]

1. Generator owner/operator to develop (or retrieve from generator manufacturer) the Generator Capability Curve for each non-exempt generating unit. This curve shall include specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure as appropriate. [*Ref. PRC-019, R2.1.1*]

2. Generator owner/operator to show on the Generator Capability Curve and other appropriate curves (plots) that the coordination of the generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. The completed curves (plots) should show the following as appropriate (See Attachments 2 through 5):

   a) Steady state over-excitation and under excitation limiter control characteristics. [*Ref. PRC-019, R2.1.2*]

   b) Power output limit of the unit, as verified per MOD-024. [*Ref. PRC-019, R2.1.3*]

   c) Other factors that could limit megawatt or megavar capability. [*Ref. PRC-019, R2.1.4*] Example: generator step-up transformer MVA rating, generator rotor with shorted turn, steady state transmission and station auxiliary bus voltage limits, etc.

   d) Loss of excitation relay / field protection relay characteristics [*Ref. PRC-019, R2.1.5*]

   e) Coordination of the volts per hertz protection system(s), including limiters, relating to the generator, generator step-up transformer, normal station service transformer. [*Ref. PRC-019, R2.1.6*]

A. Introduction

1. **Title: Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection**

2. **Number:** PRC-019-1

3. **Purpose:** Ensure generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Dates:** To be determined:

   One year beyond Board of Trustee adoption for Requirement 1

   Two years beyond Board of Trustee adoption 1st 20% compliant with Requirement 2 and Requirement 3

   Three years beyond Board of Trustee adoption 2nd 20% compliant with R2, R3

   Four years beyond Board of Trustee adoption 3rd 20% compliant with R2, R3

   Five years beyond Board of Trustee adoption 4th 20% compliant with R2, R3

   Six years beyond Board of Trustee adoption 5th 20% compliant with R2, R3

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the Generator Owner requirements in R2.

R2. Unless exempted by the Regional Reliability Organization in accordance with R1, the Generator Owner shall have study results that show it verified that its generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. This study shall include the following:

R2.1. Plots, or data that could be plotted for the following:

R2.1.1. Generator capability curve, including specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure.

R2.1.2. Steady state over-excitation limiter and under-excitation limiter control characteristics.

R2.1.3. MW limit of the prime mover.

R2.1.4. Any other limit that could restrict the megawatt or megavar capability.

R2.1.5. Loss of excitation / field protective relay characteristics.

R2.1.6. Volts-per-hertz protection settings including volts-per-hertz limiters in the automatic voltage regulator.

R3. The Generator Owner shall have the information in R2.1.1 through R2.1.6 available to show to the Regional Reliability Organization upon request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall, within 30 calendar days of a request, provide to Generator Owners its exemption criteria defined in accordance with R1.

M2. The Generator Owner shall have evidence it showed the Regional Reliability Organization the information identified in R2.1 through R2.1.6 within 30 calendar days of a request.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC for the Regional Reliability Organization.

Regional Reliability Organization for Generator Owners.

1.2. Compliance Monitoring Period and Reset Timeframe

The compliance reset period is one calendar year.

1.3. Data Retention

The Generator Owner shall retain all current information needed to show coordination. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization did not provide the exemption criteria in accordance with R1.

2.2. Level 2: The Generator Owner information on coordination of the generator voltage regulator controls and limit functions does not address one of the requirements identified in accordance with R2.1.1 through R2.1.6.

2.3. Level 3: Not applicable.

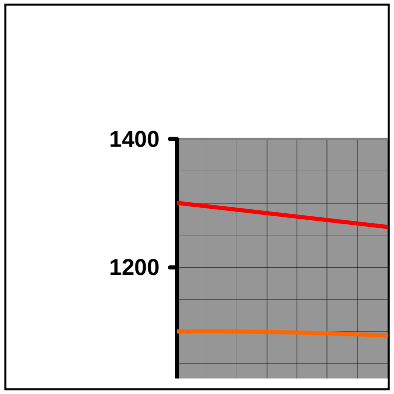
2.4. Level 4: The Generator Owner information on coordination of the generator voltage regulator controls and limit functions does not address two or more of the requirements identified in accordance with R2.1.1 through R2.1.6.

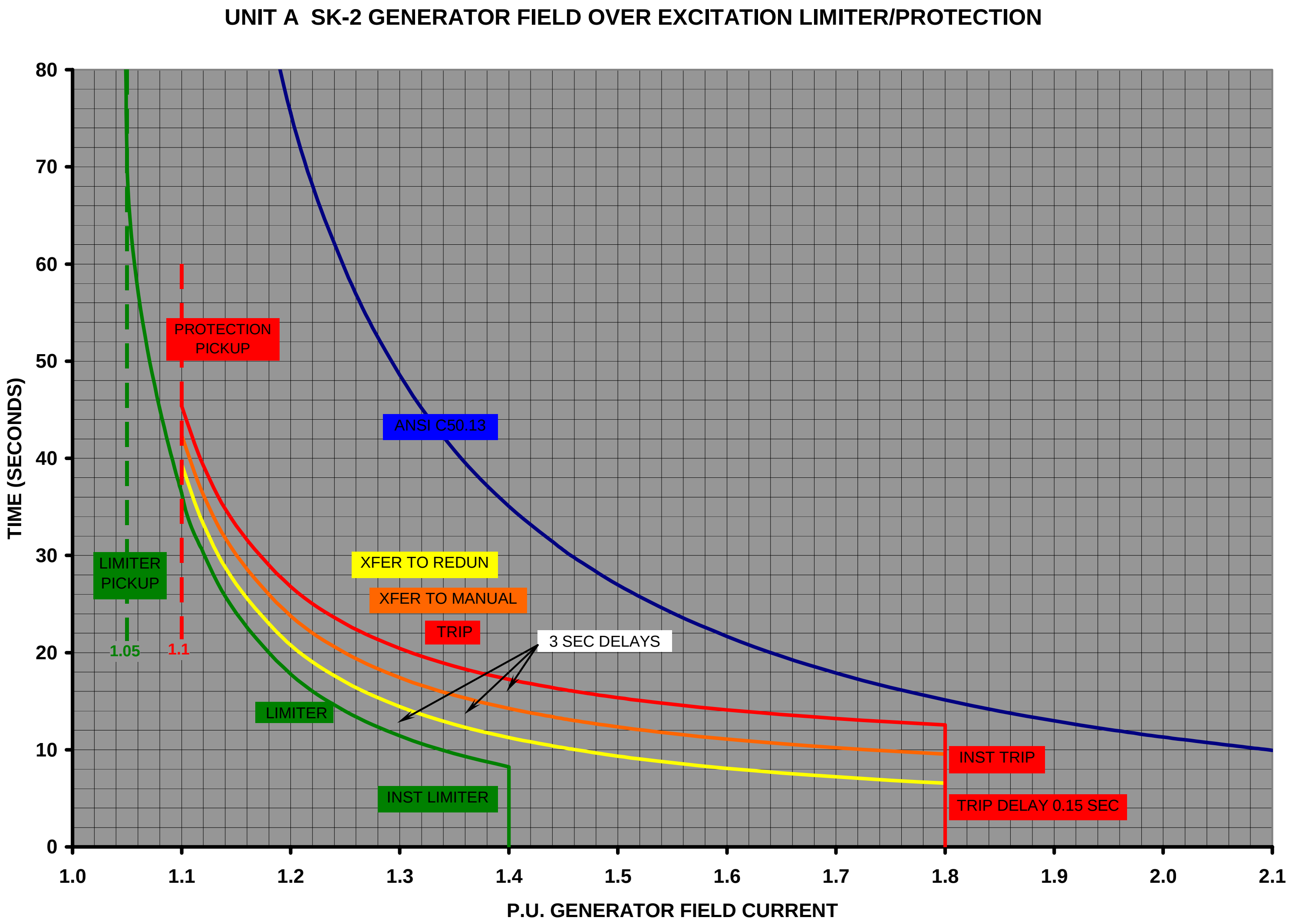
E. Regional Differences

None identified.

a. Version History

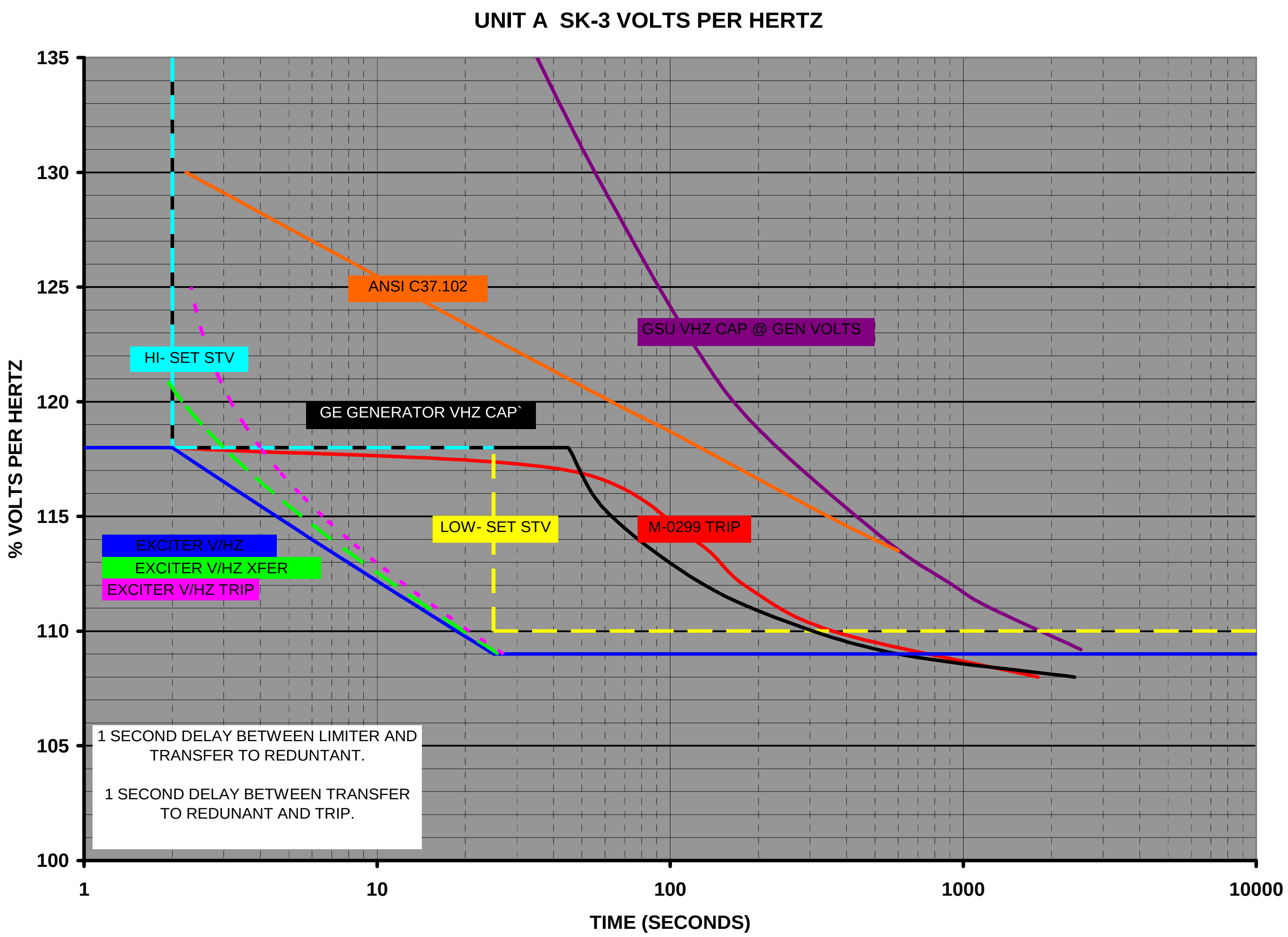
Version	Date	Action	Change Tracking

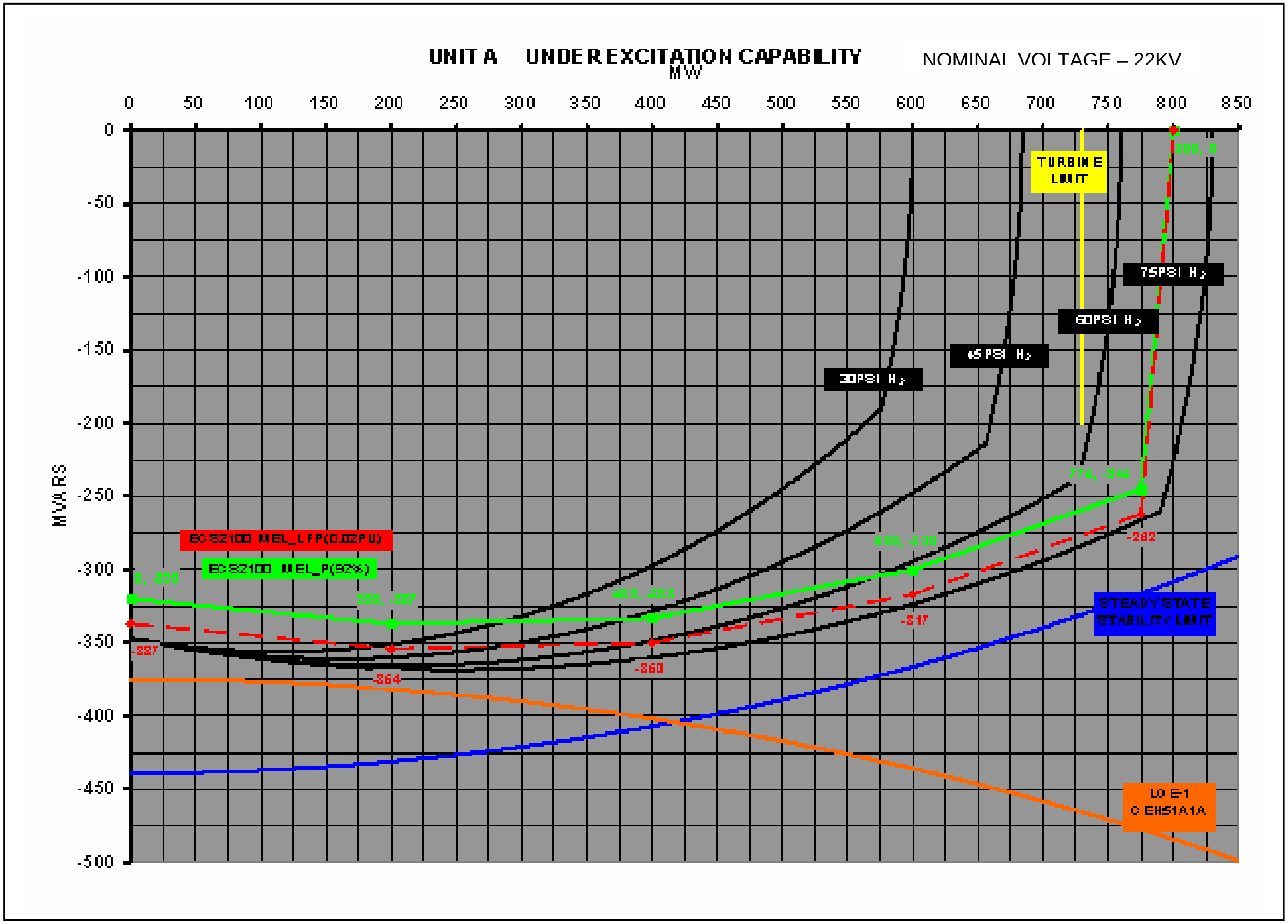

1400
1200


UNIT A SK-2 GENERATOR FIELD OVER EXCITATION LIMITER/PROTECTION
80
70
60
50
40
30
20
10
0
TIME (SECONDS)
1.0
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
2.1
P.U. GENERATOR FIELD CURRENT
PROTECTION PICKUP
ANSI C50.13
LIMITER PICKUP
XFER TO REDUN
XFER TO MANUAL
TRIP
3 SEC DELAYS
1.05
1.1
LIMITER
INST TRIP
INST LIMITER
TRIP DELAY 0.15 SEC

For Field Test Purposes Only

Attachment 4




UNIT A UNDER EXCITATION CAPABILITY
NOMINAL VOLTAGE – 22KV
MW
MVARS
0
50
100
150
200
250
300
350
400
450
500
550
600
650
700
750
800
850
-50
-100
-150
-200
-250
-300
-350
-400
-450
-500
TURBINE LIMIT
75PSI H2
60PSI H2
45PSI H2
30PSI H2
EC SZ100 MEL_LFP(0.02PU)
EC SZ100 MEL_P(92%)
0, -320
200, -337
400, -333
600, -300
776, -246
800, 0
-337
-364
-360
-317
-282
STEADY STATE STABILITY LIMIT
LOE-1
CEH51A1A

Circle and Radius Equations

Equations used to plot the different segments of the Generator Capability Curve.

CENTER AND RADIUS OF CIRCLE GIVEN THREE POINTS $(X_1\ Y_1)$ $(X_2\ Y_2)$ $(X_3\ Y_3)$

$AX^2 + CY^2 + BXY + DX + EY + F = 0$ WHERE: $A = C$ and $B = 0$

COMPLETING THE SQUARE:

$$A\left(X + \frac{D}{2A}\right)^2 + A\left(Y + \frac{E}{2A}\right)^2 + F - \frac{D^2 + E^2}{4A} = 0$$

STANDARD CIRCLE EQN.

$$(X - H)^2 + (Y - K)^2 = R^2$$

CENTER COORDINATES: $X_C = -\dfrac{D}{2A}$ $Y_C = -\dfrac{E}{2A}$

RADIUS LENGTH: $R = \sqrt{\dfrac{D^2 + E^2}{4A^2} - \dfrac{F}{A}}$

$$A = \begin{vmatrix} X_1 & Y_1 & 1 \\ X_2 & Y_2 & 1 \\ X_3 & Y_3 & 1 \end{vmatrix} \qquad D = -\begin{vmatrix} (X_1^2 + Y_1^2) & Y_1 & 1 \\ (X_2^2 + Y_2^2) & Y_2 & 1 \\ (X_3^2 + Y_3^2) & Y_3 & 1 \end{vmatrix}$$

$$E = \begin{vmatrix} (X_1^2 + Y_1^2) & X_1 & 1 \\ (X_2^2 + Y_2^2) & X_2 & 1 \\ (X_3^2 + Y_3^2) & X_3 & 1 \end{vmatrix} \qquad F = -\begin{vmatrix} (X_1^2 + Y_1^2) & X_1 & Y_1 \\ (X_2^2 + Y_2^2) & X_2 & Y_2 \\ (X_3^2 + Y_3^2) & X_3 & Y_3 \end{vmatrix}$$

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? ________ Hours
2. What methodology / tools were used to perform the coordination studies?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? _________
4. How long did it take to analyze the technical information and draw the curves (plots)? ________ Hours
5. List any material costs associated with this study.

   ____

   ____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? ________ (Yes or No)
7. If not, list the devices that needed configuration changes:

   ____

   ____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?

   ____

   ____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)
10. Name of person completing form: ______________ Phone number ____________

    Company name _________________________________

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.

SERC Field Test Guidelines

Generator Performance During Frequency and Voltage Excursions

NERC Draft Reliability Standards PRC-024

Revision History

Revision	Date	Comments
0	March 2, 2007	GSFT-TF finalized SERC PRC-024-1 Guideline for Field Test purposes.

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and Region Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-024.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-024.

Effective Dates – Not Applicable:

Table of Contents

I. Introduction 4
II. Definitions 4
III. Requirements/Expectations 5
  A. Generator Exemption Criteria [*Ref. PRC-024, R3*] 5
  B. Variance Procedures [*Ref. PRC-024, R4*] 5
  C. Requirements for Generators to Remain Connected During System Frequency and Voltage Excursions 5
    1. Frequency Excursion Requirements 5
    2. Voltage Excursion Requirements 6
    3. SERC Documentation Requirements 8

List of Attachments

Attachment 1: Draft NERC Reliability Standard PRC-024

I. Introduction

In order to effectively evaluate the electric system's performance, Transmission Planners make implicit or explicit assumptions regarding the ability of generators to remain on-line during frequency and voltage excursions. The validity of these assumptions are critical for planning and operating studies of the reliability of the electric system. These assumptions are especially critical for studies used to develop "safety-net" schemes such as Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS). Incorrect assumptions regarding the ability of generators to remain on-line would lead to ineffective or suboptimal load shedding schemes.

This SERC field test guideline for the NERC Reliability Standards PRC-024 is intended to:

1) Provide guidance for SERC Generator Owners to address verification of the capability of generators to remain connected to the electrical grid during defined system frequency and voltage excursions.
2) Provide guidance for SERC Generator and Transmission Owners to:
    a. Address coordination between the generator under frequency protection and SERC's UFLS program.
    b. Address coordination of generator protection with transmission protection systems.
3) Document the GSFT-TF recommended exemption criteria, variance requests, and sister unit philosophy.

It is recognized that any effort to verify the capability of generators to remain connected during defined system frequency and voltage excursions does not constitute a guarantee by the Generator Owner. There are systems in a generation plant where practical means are not readily available to determine how they would respond to the frequency and voltage excursion, and/or if a trip of these systems would subsequently cause an immediate or delayed generator trip. These systems include, but are not limited to, Boiler Control Systems, Adjustable Speed Drives, and station auxiliary loads (motor performance due to undervoltage or underfrequency, and loss of load due to dropout of unlatched contactors).

Therefore, the GSFT-TF is recommending for these field test activities a verification process meant to uncover protection system coordination issues that would almost certainly lead to a generator tripping if exposed to the defined frequency or voltage excursion. As such, the likelihood of the generator remaining on-line during the defined frequency or voltage excursion would be increased and lend some additional validity to study assumptions made by Transmission Planners.

II. Definitions

1. **Exempt Generation –** Generator(s) that meets the exemption criteria for a particular

requirement.

2. **Low Voltage Ride Through (LVRT) Capability –** the ability of a generator to remain on-line when subjected to a defined transmission system voltage excursion.
3. **Variance –** a deviation in the established RRO requirement for a generator to remain on-line during system frequency and/or voltage excursion.

III. Requirements/Expectations

A. Generator Exemption Criteria [*Ref. PRC-024, R3*]

It is prudent to exempt small generators that, if they are unable to stay on-line for certain frequency and voltage excursions, would be expected to have an insignificant impact on the reliability of the bulk electric system. Therefore, generators interconnected to a power system operated at a voltage of less than 100 kV or having a nameplate rating of less than or equal to 75 MVA are exempt from complying with SERC's requirements for generators to remain connected during the defined frequency and voltage excursions. On a case by case basis the Transmission Planner may identify certain generators that are less than 75 MVA, but have a significant impact on transmission voltage security, and cannot be exempted from the low voltage ride-through requirements.

B. Variance Procedures [*Ref. PRC-024, R4*]

It is recognized that efforts to ensure coordination between generator protection systems and the Region's defined voltage and frequency excursion could result in identification of generators who have systems that will be unable to achieve coordination. In those instances, the Generator Owner can request a Variance from SERC. SERC, the Generator Owner, and the Transmission Owner will then work together to determine if the requested Variance would adversely impact bulk power system reliability. In no instances should any protection or control scheme setting be endorsed that exposes a generating unit to damage.

C. Requirements for Generators to Remain Connected During System Frequency and Voltage Excursions

1. Frequency Excursion Requirements

a) To ensure coordination with under-frequency load shed (UFLS) schemes, generator protection schemes are expected to be set such that the generator would remain on-line when subjected to the frequency excursion curve defined in Figure 1 [*Ref. PRC-024, R1*] .

b) The process of determining coordination with the frequency excursion curve defined in Figure 1 assumes that the corresponding transmission system voltage remains within scheduled limits.

c) The Generator Owner can demonstrate coordination with transmission system UFLS schemes through the development of a coordination curve (reference Figure 2).

d) If generator protection schemes are set such that the generator would not be expected to stay on line for the frequency excursion curve shown in Figure 1, the Generator Owner should investigate if the schemes can be relaxed without exposing the generator to potential damage. This could include consultation with the Original Equipment Manufacturer. If the protection schemes cannot be adjusted such that the generator would stay on line for the frequency excursion shown in Figure 1, the Generator Owner should request a Variance (reference Section B).

e) To reasonably assure the generators capability to remain on-line during the frequency excursion defined in Figure 1, expected performance of the following systems should be evaluated:

(1) Turbine Generator protection
Specific protective relays that should be checked for coordination with the frequency excursion defined in Figure 1 include turbine frequency protection and volts per hertz.

(2) Nuclear Power Plant Systems
Systems that are both unique to Nuclear power plant systems and are potentially sensitive to under frequency excursions should be checked for coordination with the frequency excursion defined in Figure 1. These systems include Reactor Coolant Pumps for PWRs and Reactor Recirc Pumps for BWRs.

f) To ensure coordination with generator turbine underfrequency protection schemes, UFLS schemes are expected to be designed to initiate load shed for frequency excursions which are less severe than the curve defined in Figure 1. In order to show the coordination, the Transmission Owner is required to develop a coordination curve – an example is shown in Figure 3. This activity should occur at the same time that the UFLS scheme review of the set points and timing is conducted per NERC Reliability Standard PRC-006 R.1.4.1. [*Ref. PRC-024, R2.1.*]

2. Voltage Excursion Requirements

a) To ensure the interconnected transmission system is planned appropriately per the requirements in TPL-001 through TPL-004, generator protection schemes are expected to be set such that the generator would have sufficient LVRT capability to remain on-line when subjected to the voltage excursion curve defined in Figure 4 [*Ref. PRC-024, R1*]

b) The process of determining coordination with the voltage excursion curve defined in Figure 4 assumes that the corresponding transmission system frequency remains at 60 Hertz.

c) The SERC under-voltage excursion curve, shown in Figure 4, is defined at the generator's highside transmission bus. Note that the time at Voltage 0 in Figure 4 would typically be dictated by transient stability limits. If the LVRT Capability of the generator corresponds to a Voltage 0 time which is less than the transient stability limit, the Generator Owner should work with the Transmission Owner to determine if any additional action is required.

d) The technical drivers dictating the flat and then gradual recovery to 80% within 2 seconds depicted on the generator LVRT curve in Figure 4 include:

(1) Captured event data verify that fault activity resulting in similar voltage signatures as depicted in Figure 4 have occurred in SERC as a result of fault activity.
(2) In order to design secure UVLS safety net schemes, SERC utilities have installed UVLS schemes with logic to trip load include time delays from approximately 1 to just beyond 2.0 seconds. Thus, a minimum LVRT of 2.0 seconds is required.
(3) Detailed dynamic simulations consistently confirm that the transmission system does not have to be significantly further stressed to transition from a delayed voltage recovery of 2 second at the highside of generation plants to a "no recovery" wide area fast voltage collapse scenario. Therefore, if critical generation units trip before UVLS schemes can operate, the transmission system will have exposure to credible wide area voltage collapse scenarios that may or may not be contained to a control area.

e) To reasonably assure the generators LVRT Capability to withstand the voltage excursion defined in Figure 4, expected response to the voltage excursion by the following systems should be evaluated:
(1) Station Service Bus Under Voltage Relays
All station service under voltage relays which protect buses and/or individual loads that contain known loads critical to the generator remaining on-line should coordinate with the under-voltage excursion curve depicted in Figure 4.
(2) Generator Under Voltage Relays
The settings of any generator under voltage relay should coordinate with the under-voltage excursion curve depicted in Figure 4.
(3) Loss of Field and/or Power Potential Source Exciter PPT Secondary Relaying
The setting of any loss of field and/or power potential source exciter PPT secondary relay(s) should be checked for coordination with the under-voltage excursion curve depicted in Figure 4.
(4) Generator Backup relays (Overcurrent and/or Distance)

Suggested screening method for Generator Backup Distance relay: 1) Note the time delay. 2) Note the per unit voltage at the time delay noted in Step 1. 3) Calculate the corresponding impedance seen by the relay. Note that an increase in per unit voltage can generally be assumed on the low side of the generator GSU.

(5) Nuclear Power Plant Loss of Offsite Power Relays.

f) If generators are unable to withstand the under-voltage excursion shown in Figure 4, the Generator Owner should investigate the possibility of increasing the LVRT Capability of the Generators. If the voltage excursion withstand capability cannot be adjusted such that the generator would be expected to remain on line for the under-voltage excursion shown in Figure 4, the Generator Owner should request a Variance (reference Section B).

g) To ensure coordination between generator unit and transmission protection, the Transmission Owner and the Generator Owner should exchange relay setting information and develop coordination plots. These coordination plots should depict generator back-up protection and transmission system back-up protection, including UVLS protection, as appropriate. [Ref. PRC-024, R2.2]

3. SERC Documentation Requirements

a) SERC shall provide documentation of its excursion requirements, exemptions, and variance procedure to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval. [Ref. PRC-024, R5]

b) SERC shall, at least every five years, review and, as necessary, update its requirements, exemption criteria, and variance procedure. [Ref. PRC-024, R6]

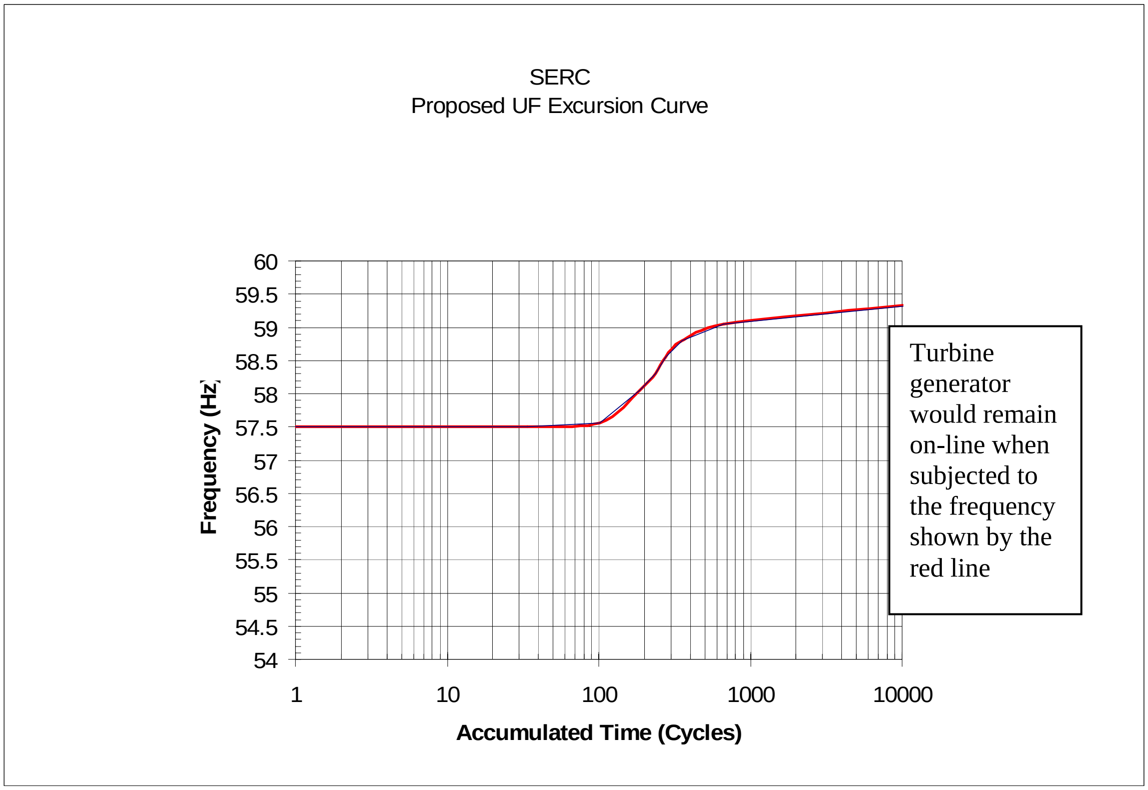

SERC
Proposed UF Excursion Curve
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
Frequency (Hz)
1
10
100
1000
10000
Accumulated Time (Cycles)
Turbine generator would remain on-line when subjected to the frequency shown by the red line

Figure 1

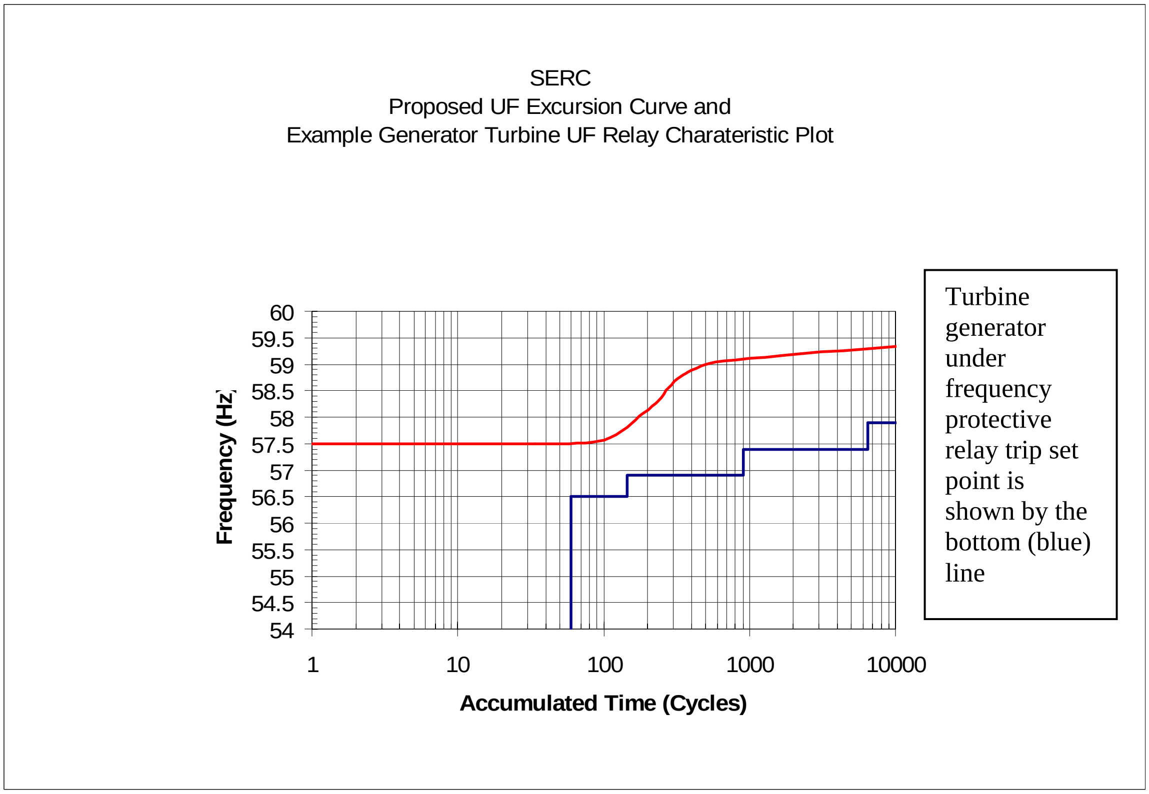

SERC
Proposed UF Excursion Curve and
Example Generator Turbine UF Relay Charateristic Plot
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
1
10
100
1000
10000
Accumulated Time (Cycles)
Turbine generator under frequency protective relay trip set point is shown by the bottom (blue) line

Figure 2

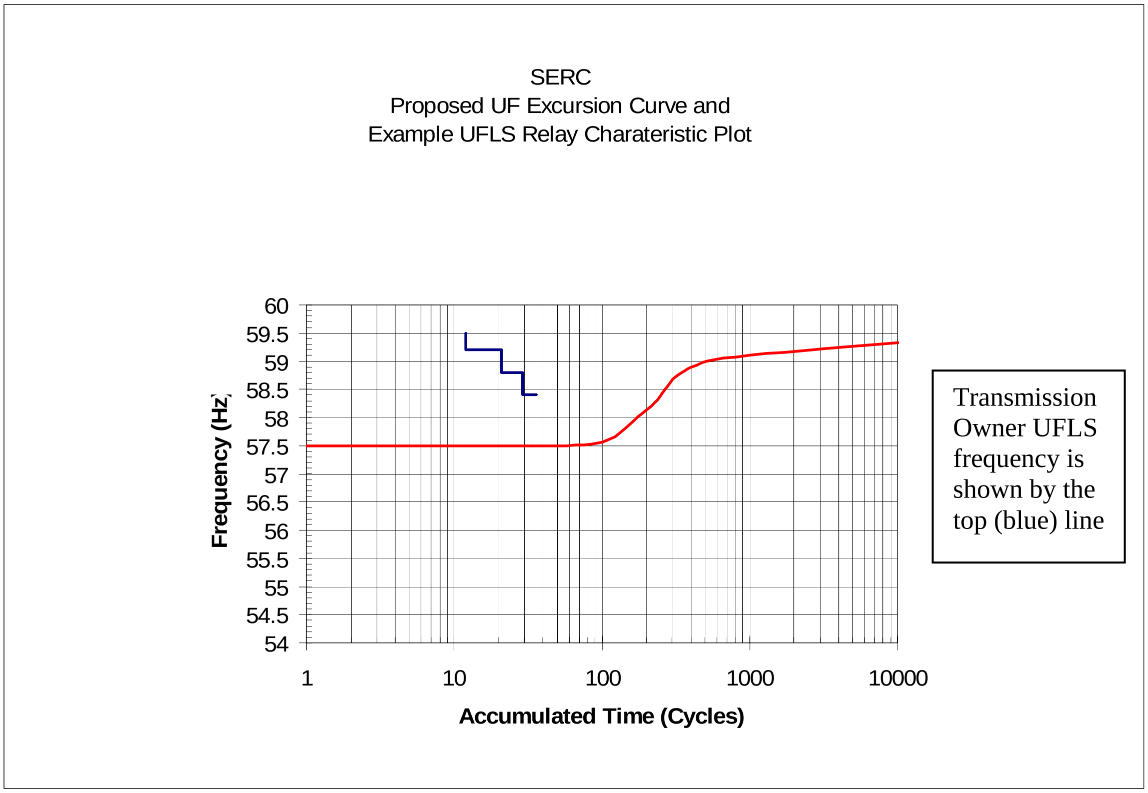

SERC
Proposed UF Excursion Curve and
Example UFLS Relay Charateristic Plot
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
1
10
100
1000
10000
Accumulated Time (Cycles)
Transmission Owner UFLS frequency is shown by the top (blue) line

Figure 3

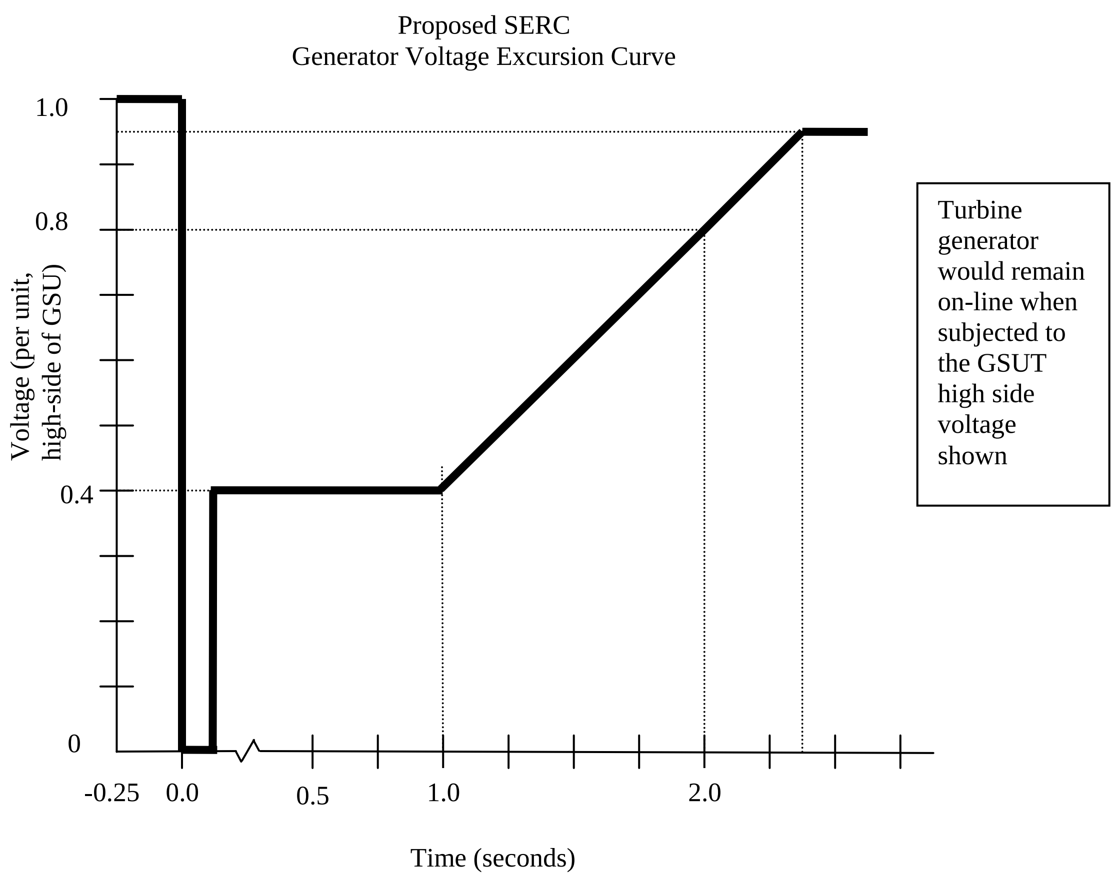

Proposed SERC
Generator Voltage Excursion Curve
1.0
0.8
0.4
0
Voltage (per unit, high-side of GSU)
-0.25
0.0
0.5
1.0
2.0
Time (seconds)
Turbine generator would remain on-line when subjected to the GSUT high side voltage shown

Figure 4

Attachment 1

A. Introduction

1. **Title:** **Generator Performance During Frequency and Voltage Excursions**
2. **Number:** PRC-024-1
3. **Purpose:** To ensure that generators remain connected to the electrical grid during voltage and frequency excursions and are not normally tripped manually or by preset protection schemes during frequency and voltage excursions.
4. **Applicability**
   - **4.1.** Regional Reliability Organizations.
   - **4.2.** Generator Owners.
   - **4.3.** Transmission Owners.
5. **Proposed Effective Dates:** **To be determined:**

   Requirement 1 through Requirement 6 – One year beyond Board of Trustee adoption

   Requirement 7 – Two years beyond Board of Trustee adoption

B. Requirements

R1. The Regional Reliability Organization shall establish requirements for generators to remain connected during system frequency and voltage excursions expressed as a function of:

- **R1.1.** Time duration in seconds or cycles.
- **R1.2.** Amplitude or magnitude of the excursion.
- **R1.3.** Relationship between time and amplitude or magnitude.

R2. The Regional Reliability Organization shall establish and maintain requirements for generators to remain connected during frequency and voltage excursions. These requirements shall include:

- **R2.1.** Coordination between the generator under frequency protection and the regional Under Frequency Load Shedding (UFLS) program.
- **R2.2.** Coordination of generator protection, including back-up protection, with transmission Protection Systems.

R3. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the regional requirements established in accordance with R1 and R2.

R4. The Regional Reliability Organization shall establish and maintain a procedure for handling variances (i.e., different criteria or methods) from the Regional Reliability Organization's requirements established in R1 and R2, including steps for requesting and approving such variances.

R5. The Regional Reliability Organization shall provide documentation of its excursion requirements, exemptions, and variance procedure to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval.

R6. The Regional Reliability Organization shall, at least every five years, review and, as necessary, update its requirements, exemption criteria, and variance procedure.

R7. Generator Owners and Transmission Owners shall comply with the regional requirements for coordination of generator protection defined in R2 and any approved variances.

Attachment 1

A. Measures

M1. The Regional Reliability Organization shall, within 30 calendar days of a request, provide NERC with its requirements, exemption criteria, and variance procedure for generators to withstand excursions in voltage and frequency.

M2. The Regional Reliability Organization shall have evidence it provided the requirements, criteria and procedures to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval.

M3. The Regional Reliability Organization shall have evidence it reviewed and updated its requirements, criteria and procedures as required in R6.

M4. Generator Owners and Transmission Owners shall, within 30 calendar days of a request, provide the Regional Reliability Organization with documentation that it met the regional requirements for coordination of generator protection defined in R1 and R2 and any approved regional variances.

Generator Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? Hours
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic.
4. How many man-hours did it take to develop the methodology / tools?
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic? ☐Yes ☐ No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? Hours
7. List any material costs associated with the generator frequency withstand capability portion of this field test.
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic.
11. How many man-hours did it take to develop the methodology / tools?

Generator Owner PRC-024 SERC Field Test Reporting Form

12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☐Yes ☐ No

    If no please attach additional information as appropriate.

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? Hours

14. List any material costs associated with the generator LVRT capability portion of this field test.

15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

17. Name of the person completing the form: Phone Number Company Name

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

Transmission Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the UFLS characteristics? Hours
2. If frequency plots were created, what methodology / tools were used to construct the frequency coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic.
4. How many man-hours did it take to develop the methodology / tools?
5. Did the results indicate the UFLS characteristic coordinates with the draft SERC frequency Characteristic? ☐Yes ☐ No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? Hours
7. List any material costs associated with the generator frequency withstand capability portion of this field test.
8. How long did it take to assemble (bring together) the technical data needed to plot the transmission system backup protection characteristic applicable for the draft SERC LVRT curve? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic and associated generator backup relay characteristics.
11. How many man-hours did it take to develop the methodology / tools?

Transmission Owner PRC-024 SERC Field Test Reporting Form

12. Did the results indicate coordination with the draft LVRT characteristic? ☐Yes ☐ No

    If no please attach additional information as appropriate.

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? Hours

14. List any material costs associated with the transmission LVRT capability portion of this field test.

15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

17. Name of the person completing the form: Phone Number Company Name

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

Attachment 2
Standard Redlines

- **MOD-026_Draft for Field Test (GSFT-TF revised 5-3-07).doc**
- **MOD-027_Draft for Field Test (GSFT-TF revised 5-3-07).doc**
- **PRC-019_Draft for Field Test (GSFT-TF revised 5-3-07).doc**

A. Introduction

1. **Title:** **Verification of Models and Data for Generator Excitation System Functions**
2. **Number:** MOD-026-1
3. **Purpose:** To ensure accurate information on generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) is available for models used to assess Bulk Electric System reliability.
4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner

   4.3. Transmission Planner.

5. **Proposed Effective Date:** ~~To be determined.~~ The effective date should be delayed for 2 years, then phased in over at 20% per year over the next 5 years.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of models and data associated with generator excitation system functions including voltage regulator controls, limiters, compensators, and power system stabilizers. These procedures shall include the following:

R1.1. Generating unit exemption criteria ~~including documentation of those units that are exempt from a portion or all of these procedures~~. [exempt generators 75 MVA or less or generators not directly connected to the 100kV system through their step-up transformer.]

R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.3. A list of acceptable models to be used and procedures for revising the list of acceptable models.

~~**R1.3.**~~**R1.4.** Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.

~~**R1.4.**~~**R1.5.** Information to be reported related to generator excitation system functions:

~~**R1.4.1.**~~**R1.5.1.** Verified manufacturer and type of excitation system/voltage regulator control system (for example, static, brushless, rotating, etc.).

~~**R1.4.2.**~~**R1.5.2.** Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits.

~~**R1.4.3.**~~**R1.5.3.** Verified static set points for under and over excitation limiters.

~~**R1.4.4.**~~**R1.5.4.** Verified line drop compensator settings.

~~**R1.4.5.**~~**R1.5.5.** Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

~~R1.4.6.~~R1.5.6. Verified model for each power system stabilizer with associated gains, time constants, and limits. Generator owners commissioning new PSSs will supply the Transmission Planner applicable test results provided upon commissioning. This includes results of the Gain Margin test, Phase Compensation test, and on-line step in voltage tests with and without the PSS in service.

~~R1.4.7. Confirmation that the verification was conducted with the voltage regulator in the automatic voltage control mode~~

~~R1.4.8.~~R1.5.7. Method of verification used.

~~R1.4.9.~~R1.5.8. Date of verification.

R2. The Regional Reliability Organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its models and data associated with generator excitation system functions per MOD-026 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for the verification and reporting of models and data associated with its generator excitation system functions in accordance with MOD-026 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure for verification and reporting of generator excitation system data, and any revisions to that procedure were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with its generator excitation system functions, consistent with the Regional Reliability Organization procedure.

A. Introduction

1. **Title:** **Verification of Generator Unit Frequency Response**

2. **Number:** MOD-027-1

3. **Purpose:** To provide verification of generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

   4.3. Transmission Planner

5. **Proposed Effective Date:** To be Determined. Because of the need to develop new tools and methods to capture and analyze the results and time required to validate each generator, the effective date should be delayed for 2 years, then phased in over at 20% per year over the next 5 years.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator unit frequency response. These procedures shall include the following:

R1.1. Response time to be modeled, ~~e.g. up to~~at least 60~~30~~ seconds~~ for steam units, up to 45 seconds for hydro units, etc~~.

R1.2. Generating unit exemption criteria~~ including documentation of those units that are exempt from a portion or all of these procedures~~. [exempt generators 75 MVA or less or generators not directly connected to the 100kV system through their step-up transformer.]

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc. [Standard should include, but not be limited to, an event based methodology as specified in section III.D.2 of the SERC Field Test Guideline for Verification of Generator Unit Frequency Response (draft NERC Reliability Standard MOD-027).]

R1.4. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.[Standard should allow documented configuration controls as a means of ensuring validated unit response remains applicable]

R1.5. Information to be reported related to generator unit frequency response:

~~**R1.5.1.**Verified manufacturer and type of speed governor controls.~~

~~**R1.5.2.**~~**R1.5.1.** Verified model for each speed governor control~~ with any associated deadband, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.)~~.

~~R1.5.3.~~R1.5.2. Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response).

~~R1.5.4.~~R1.5.3. Method of verification and conditions of the verification including status of controls.

R2. The Regional Reliability Organization shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying and reporting its generator unit frequency response per MOD-027 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for verifying and reporting generator unit frequency response in accordance with MOD-027 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure, and any revisions to that procedure, for verification and reporting generator unit frequency response was provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with generator unit frequency response, consistent with the Regional Reliability Organization procedure.

A. Introduction

1. **Title:** **Coordination of Generator Voltage Regulator Controls with ~~Unit~~ Generator Capabilities and Protection**

2. **Number:** PRC-019-1

3. **Purpose:** Ensure generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Dates:** To be determined:

   One year beyond Board of Trustee adoption for Requirement 1

   Two years beyond Board of Trustee adoption 1st 20% compliant with Requirement 2 and Requirement 3

   Three years beyond Board of Trustee adoption 2nd 20% compliant with R2, R3

   Four years beyond Board of Trustee adoption 3rd 20% compliant with R2, R3

   Five years beyond Board of Trustee adoption 4th 20% compliant with R2, R3

   Six years beyond Board of Trustee adoption 5th 20% compliant with R2, R3

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the Generator Owner requirements in R2. [exempt generators 75 MVA or less or generators not directly connected to the 100kV system through their step-up transformer.]

R2. Unless exempted by the Regional Reliability Organization in accordance with R1, the Generator Owner shall have study results that show it verified that its generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. This study shall include the following:

R2.1. Plots~~, or data that could be plotted for~~ to show the following, if applicable:

R2.1.1. Generator capability curve, including specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure.

R2.1.2. Steady state over-excitation limiter and under-excitation limiter control characteristics.

R2.1.3. Verified MW ~~limit of the prime mover~~capability of the generating unit [as developed in MOD-024].

R2.1.4. ~~Any other limit that could restrict the megawatt or megavar capability~~.

R2.1.5. Loss of excitation / field protective relay characteristics.

R2.1.6. Volts-per-hertz protection settings including volts-per-hertz limiters in the automatic voltage regulator.

R3. The Generator Owner shall have the information in R2.1.1 through R2.1.6 available to show to the Regional Reliability Organization upon request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall, within 30 calendar days of a request, provide to Generator Owners its exemption criteria defined in accordance with R1.

M2. The Generator Owner shall have evidence it ~~showed the Regional Reliability Organization the information~~performed the studies identified in R2.1 through R2.1.6 within 30 calendar days of a request.

Attachment 3
MOD-026 Test Results

- **SERC MOD-026 Field Test Reporting Form - COE 6-8-2007.pdf**
- **MOD-026 Reporting Form Dominion.pdf**
- **serc mod-026 field test reporting form rev 0 (1-11-07)(Completed).doc**
- **SERC MOD-026 Reporting form - Attachment 2.doc**
- **SCG Sample MOD 026 Field Test Reporting Form.doc**
- **gs5 2pct step 29 Jan 2007.JPG**
- **SCG Excitation System Model.ppt**

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : ____Unknown____ Hours
   - Setup of Test Equipment: ___8_____ Hours
   - Time to Prepare Unit for Test: ___1_____ Hours
   - Performance of Test and Data Collection: ____1____ Hours

Note: The subject testing was performed by an outside contractor. The above numbers are only observed estimates of the contractor time in each area.

2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? __Unknown __ Hours

Note: The subject testing and data analysis was performed by an outside contractor.

3. Was a good correlation between the exciter model and the OCSR test obtained? (**Yes** or No)

   If no please attach additional information as appropriate.

4. What was the magnitude of the step input applied? _____2 %________________
5. List any material costs associated with this testing. __Currently our organization does not have all of the test equipment, software and testing experience needed to perform the testing and data analysis required by this proposed standard. All testing, data collection and analysis for this field test was performed by an outside contract at a cost of approximately $20, 000.
   ____
   ____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (**Yes** or No). If no, please attach additional information as appropriate.
7. Please list any suggested changes to the guideline?
   ____
   ____
   ____

MOD-026 SERC Field Test Reporting Form

8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026). Attached.
9. Name of the person completing the form:_David Williams_ Phone Number_706.643.0313_______ Company Name_Corps of Engineers – Mobile District_____________

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name: ___Hydro Unit - X____________________**
2. **Company: _____Corps of Engineers ________________**
3. **Date: ________June 4, 2007_______________________**
4. **Submitter: ____David Williams______________________**
5. **Phone No. _____706.643.0313______________________**

1. Exciter Information:

Manufacturer: __ABB Inc. ________________________

Type of Excitation System:

- [X] Static
- [ ] Brushless
- [ ] Alternator Rectifier
- [ ] Motor Driven dc exciter
- [ ] Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: __ABB Inc. __________________

Type of Voltage Regulator:

- [ ] Analog
- [X] Digital
- [ ] Other(describe)
- [ ]

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes__X___ No____

If the answer is yes,

Manufacturer: __ABB Inc. ____________________

Type of PSS:

- [ ] Single input (delta speed/frequency type)
- [X] Dual input (integral of accelerating power)
- [ ] Other(describe)
- [ ]

Attachment 2

Reporting Form

Excitation Systems Controls

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

   See APPENDIX A and B.

5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2.

   See APPENDIX A and B.

6. Provide the data required in III.G.2 on Excitation Limit Controls.

   See APPENDIX C.

APPENDIX A: MODELS AND RATINGS

A1. Ratings

Ratings		Value	Units
Generator Base Power	Sbase	131.579	MVA
Generator Base Voltage	Ebase	13.8	kV
Rated Speed	rpm	163.6	rpm
power factor	pf	0.95	
Rated MVA and pf Field Current	ifdrated	750	
Base Air-Gap Line Field Current	ifdbase	382	A
Base Air-Gap Line Field Voltage	efdbase	145	V
Field Winding Resistance	rfdbase	0.38	ohms
Field Winding Base Temperature	rfd temp	75	C

A2. Generator Model

GENSAL: Salient Pole Generator Model

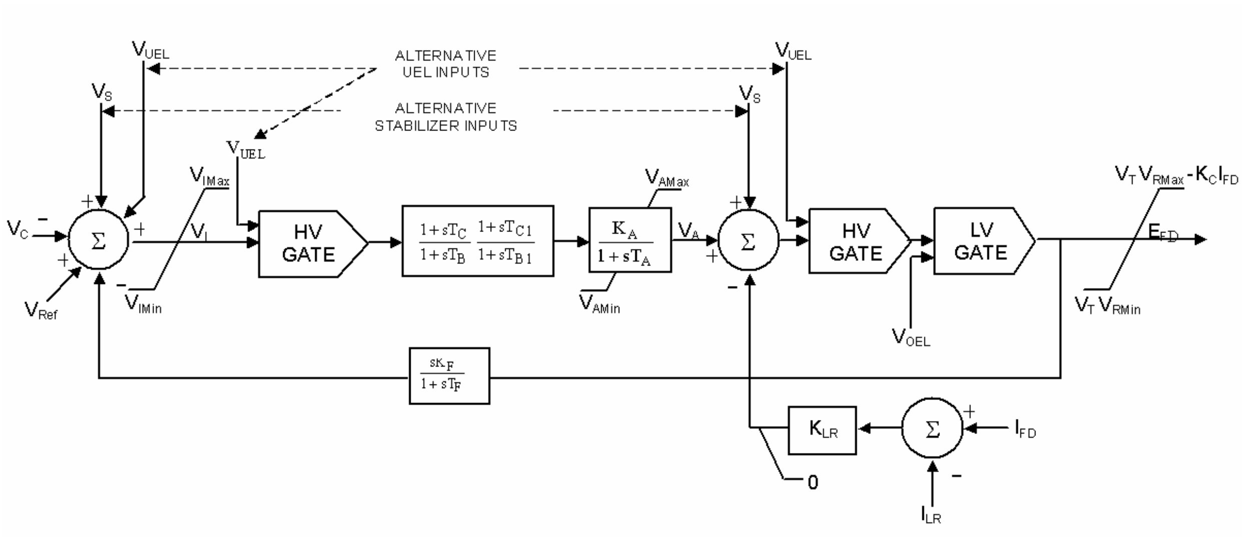
Description	Parameter	Value	Units
D-Axis O.C. Transient Time Constant	T'do (>0)	8	sec
D-Axis O.C. Sub-Transient Time Constant	T"do (>0)	0.05	sec
Q-Axis O.C. Sub-Transient Time Constant	T"qo (>0)	0.05	sec
Inertia	H	5.1	pu
Speed Damping	D	0	pu
D-Axis Synchronous Reactance	Xd	0.992	pu
Q-Axis Synchronous Reactance	Xq	0.65	pu
D-Axis Transient Reactance	X'd	0.3	pu
D-Axis/Q-Axis Sub-Transient Reactance	X"d = X"q	0.2	pu
Leakage Reactance	Xl	0.1	pu
Open Circuit Saturation factor	S(1.0)	0.172	pu
Open Circuit Saturation factor	S(1.2)	0.62	pu

A3. Excitation System Model

IEEE Type ST1A Model

Description	Parameter	Value
Alternate UEL inputs	UEL (1,2, or 3)	1
Alternate stabilizer inputs	VOS(1 or 2)	1

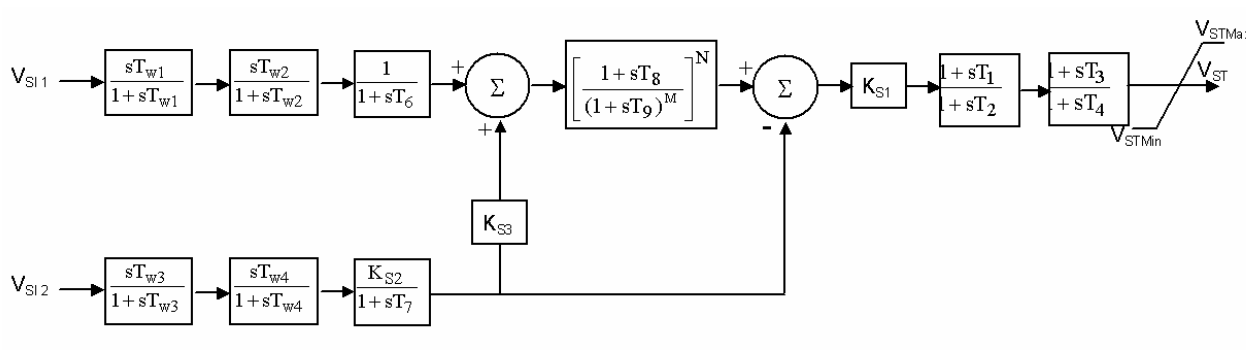
Description	Parameter	PSS OFF Value	PSS ON Value	Units
Terminal voltage transducer T.C.	Tr	0.01	0.01	sec
AVR upper limit	VIMAX	999	999	
AVR lower limit	VIMIN	-999	-999	
AVR lead time constant	TC	1	1	sec
AVR lag time constant	TB	**6**	**3.5**	sec
AVR lead time constant	TC1	0	0	sec
AVR lag time constant	TB1	0	0	sec
AVR gain	KA	**300**	**350**	
AVR time constant	TA	0	0	sec
Positive regulator output limit	VAMAX	999	999	
Negative regulator output limit	VAMIN	-999	-999	
Positive exciter output limit (ceiling)	VRMAX	3.86	3.86	
Negative exciter output limit (ceiling)	VRMIN	-3.46	-3.46	
Rectifier regulation	KC	0.046	0.046	
Exciter feedback gain	Kf	0	0	
Exciter feedback time constant	Tf (>0)	1	1	sec
Field current limiter gain	KLR	1	1	
Field current limiter setting	ILR	1.96	1.96	
Notes PSS-OFF model appropriate for open-circuit and stabilizer off conditions. **PSS-ON model appropriate for stabilizer on (normal on-line condition)**				



A4. Power System Stabilizer Model

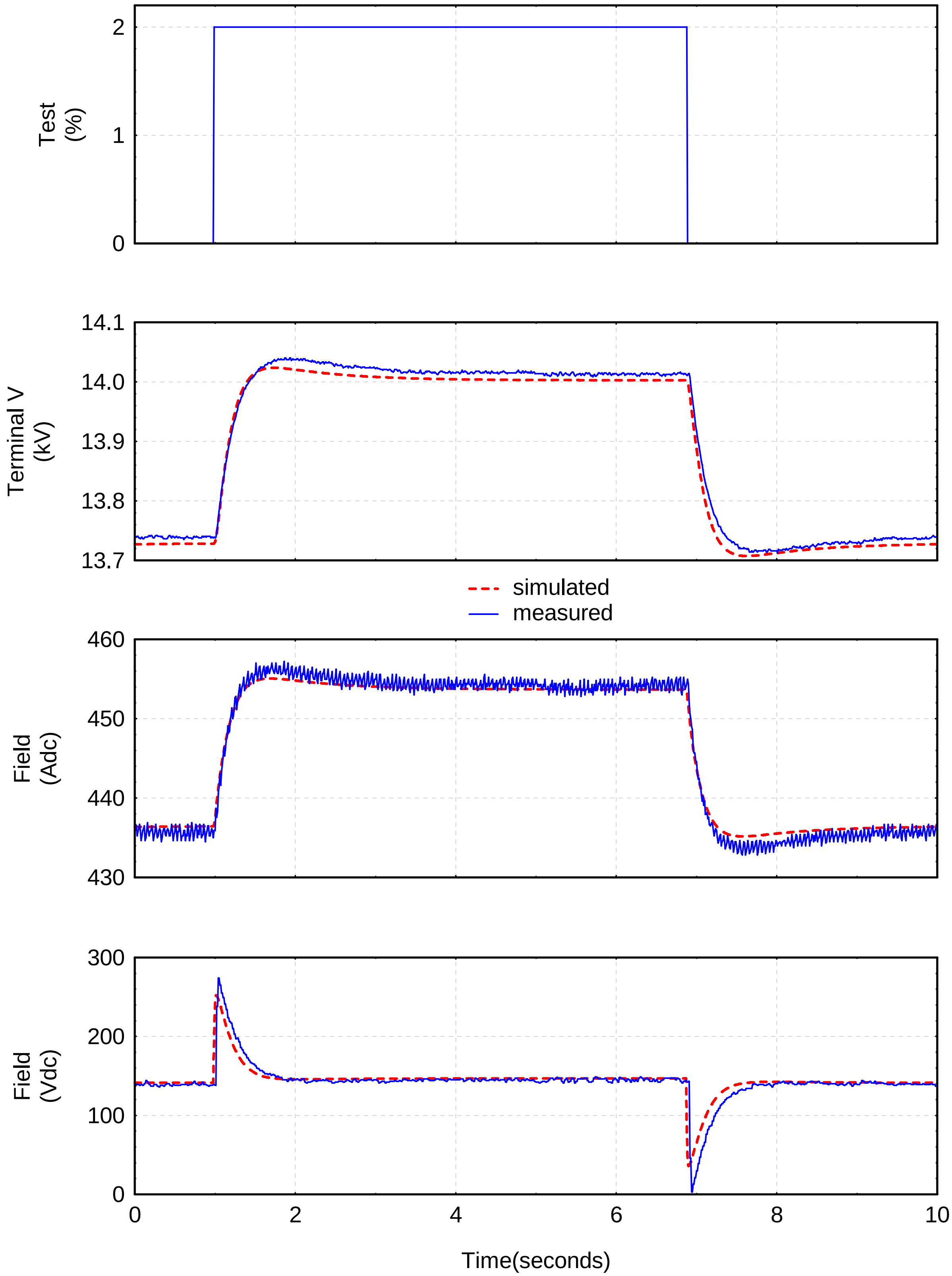
IEEE TYPE PSS2A DUAL-INPUT STABILIZER MODEL

Description	Parameter	Value	Units
First stabilizer input code	ICS1	1	Rotor speed deviation (pu)
First remote bus number	REMBUS1		
First stabilizer input code	ICS2	3	Electrical power on generator MVA base (pu)
Second remote bus number	REMBUS2		
Ramp tracking filter order	M	5	
Ramp tracking filter order	N	1	
Description	**Parameter**	**Value**	**Units**
Washout time constant	Tw1 (>0)	10	sec
Washout time constant	Tw2	10	sec
Filter time constant	T6	0	sec
Washout time constant	Tw3 (>0)	10	sec
Filter time constant	Tw4	0	sec
Washout time constant	T7	10	sec
Gain	KS2 (= T7/2H)	0.98	
Gain	KS3	1	
Ramp-tracking filter time constant	T8	0.5	sec
Ramp-tracking filter time constant	T9 (>0)	0.1	sec
Stabilizer gain	KS1	10	
Phase lead time constant	T1	0.18	sec
Phase lag time constant	T2	0.03	sec
Phase lead time constant	T3	0.12	sec
Phase lag time constant	T4	0.02	sec
Output limits	VSTMAX	0.05	pu Etref
Output limits	VSTMIN	-0.05	pu Etref
Inertia	H	5.1	MW-s/MVA
Generator Apparent Power	Sbase	131.579	MVA

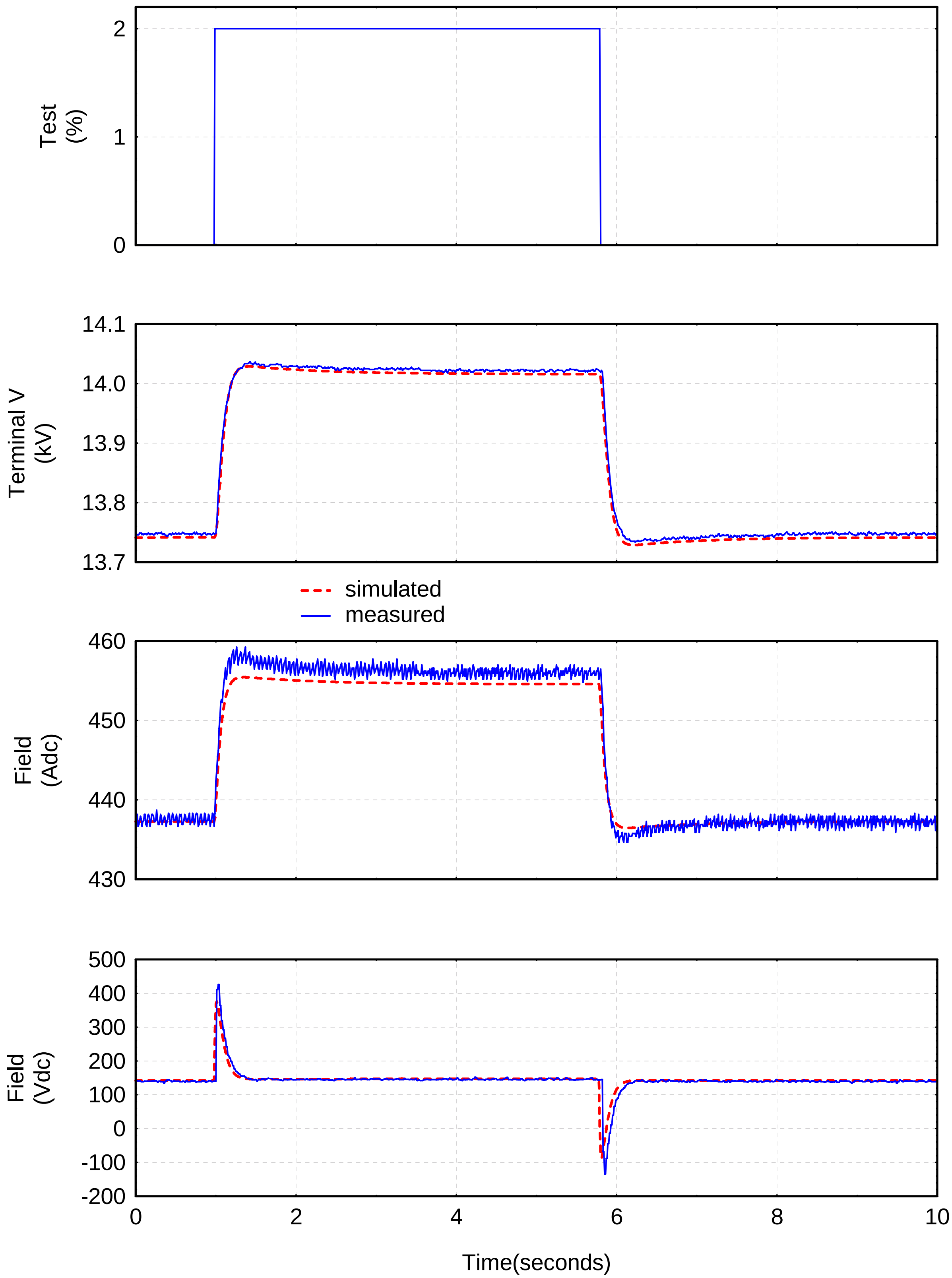


APPENDIX B: PERFORMANCE MEASUREMENTS

B3. Open Circuit Step Response, Stabilizer OFF AVR Settings



B4. Open Circuit Step Response, Stabilizer ON AVR Settings



APPENDIX C: EQUIPMENT SETTINGS

```
Parameters and Signals  04/11/2005
20:32
As Comm par Carters Unit1

202 U MACHN KV    13.80 kV
204 I MACHN KA    5.50 kA

501 U EXC V NOMINAL     272 V
502 I EXC A NOMINAL     750 A
504 U SYN V NOMINAL     430 V
515 ALPHA MIN LIMIT     15
516 ALPHA MAX LIMIT     150
517 USYN COMPENS SEL    ON
518 2DXN    5.80%

IE LIMITER: (OEL)
1301 REF1 IETH    105.00%
1302 REF2 IETH    105.00%
1303 REF1 IEMAX   160.00%
1304 REF2 IEMAX   160.00%
1305 TIME IEMAX SEL     10.0 s
1306 TC IERED MAX-TH    1.00 s
1307 TIME IE BACK INT   100.0 s
1308 not used     160.00%
1309 KOEL IE      35%

I LIMITER:
1401 REF1 I MACH TH     109.00%
1402 REF2 I MACH TH     109.00%
1403 I MACH EQUIVALENT  160.00%
1404 TIME I EQUIVALENT  10.0 s
1405 TC I MACH RED      1.00 s
1406 TIME  I BACK INT   100.0 s
1407 KOEL I  MACH 0%
1408 KUEL I  MACH 0%

PQ IEMIN LIM:     (UEL)
1501 REF0 Q(P) LIM      -50.00%
1502 REF25 Q(P) LIM     -50.00%
1503 REF50 Q(P) LIM     -40.00%
1504 REF75 Q(P) LIM     -30.00%
1505 REF100 Q(P) LIM    -18.00%
1506 KUEL Q(P) LIM      50%
1507 REF IEMIN LIM AVR  0.00%
1508 KUEL IEMIN LIM A   25%

AVR CTRL:
1901 HL REF AVR   110.00%
1902 LL REF AVR   90.00%
1903 PRESET1 REF AVR    100.00%
1904 PRESET2 REF AVR    100.00%
1905 RAMP TIME1 REF A   200.0 s
1906 RAMP TIME2 REF A   200.0 s
1907 TC FOLLOW UP AVR   10.0 s
1908 TC IMPOSED CTRL A  100.0 s
1909 Q DROOP/COMPENS    0.00%
1910 P DROOP/COMPENS    0.00%
1911 REF V/Hz LIM AVR   115.00%
1912 REF UMAX fNOM AVR  115.00%
1913 REF UMAX AVR 115.00%
1914 DELAY V/Hz LIM A   0.0 s
1915 SOFTSTART RAMP     5.0 s
1916 CEILING FACTOR A   386%

Stabilizer OFF
1917 DC GAIN AVR  300
1918 P GAIN AVR   50
1919 HF GAIN AVR  180

Stabilizer ON
1917 DC GAIN AVR  350
1918 P GAIN AVR   100
1919 HF GAIN AVR  100

1920 TA1    1.00 s
1921 TA2    1.00 s
1922 TA3    1.00 s
1923 TB1    20 ms
1924 TB2    20 ms
1925 TB3    20 ms

"AVR IN, PSS:"
2001 SEL LIM PRIORITY   OEL
2002 SEL PSS MODE ON IEEE
2003 PSS KS1      10
2004 PSS KS2      0.98
2005 PSS KS3      1
2006 PSS T1 0.18 s
2007 PSS T2 0.03 s
2008 PSS T3 0.12 s
2009 PSS T4 0.02 s
2010 PSS T7 10.00 s
2011 PSS T8 0.50 s
2012 PSS T9 0.10 s
2013 PSS TW1      10.0 s
2014 PSS TW2      10.0 s
2015 PSS TW3      10.0 s
2016 PSS TW4      0.0 s
2017 PSS N  1
2018 PSS M  5
2019 PSS P MACH MIN     10.00%
2020 not used     0.00 s
2021 not used     0.00 s
2022 Xx MACH      0.6
2023 PSS UST MAX  5.00%
2024 PSS UST MIN  -5.00%
```

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : 20 Hours
   - Setup of Test Equipment: 10 Hours
   - Time to Prepare Unit for Test: 8 Hours - Fire in boiler To 3600 RPM
   - Performance of Test and Data Collection: 12 Hours - Testing performed around unit start up
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? 4 - 6 Hours
3. Was a good correlation between the exciter model and the OCSR test obtained? (Yes or No)

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? 1 & 2 %
5. List any material costs associated with this testing.

   ____

   ____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (Yes or No). If no, please attach additional information as appropriate.
7. Please list any suggested changes to the guideline?

   ____

   ____

   ____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026).
9. Name of the person completing the form:________________ Phone Number________ Company Name______________

Send the completed report form, plots, models and documentation to

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name** ______________
2. **Company:** Dominion
3. **Date:** 4/
4. **Submitter:** ______________
5. **Phone No.** ______________

1. Exciter Information:

Manufacturer: WesTinghouse

Type of Excitation System:

- [ ] Static
- [x] Brushless
- [ ] Alternator Rectifier
- [ ] Motor Driven dc exciter
- [ ] Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: WesTinghouse WTA 300B

Type of Voltage Regulator:

- [x] Analog
- [ ] Digital
- [ ] Other(describe)
- [ ]

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes X No____

If the answer is yes,

Manufacturer: EaTon CuTler Hammer

Type of PSS:

- [ ] Single input (delta speed/frequency type)
- [x] Dual input (integral of accelerating power)
- [ ] Other(describe)
- [ ]

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : ____0.5____ Hours
   - Setup of Test Equipment: ___0.5_____ Hours
   - Time to Prepare Unit for Test: _Performed at unit startup__ Hours
   - Performance of Test and Data Collection: ___0.5_____ Hours
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? ____2____ Hours
3. Was a good correlation between the exciter model and the OCSR test obtained? (Yes or No) Yes

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? _______2%_____________
5. List any material costs associated with this testing. ___No additional material cost. This test was performed during exciter commissioning____________
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (Yes or No). If no, please attach additional information as appropriate. Yes
7. Please list any suggested changes to the guideline?
   ____
   ____
   ____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026).
9. Name of the person completing the form:Pat Longshore Phone Number 803-217-7490
   Company Name_SC Electric & Gas__

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name:** ____
2. **Company:** _________SCE&G_________________________
3. **Date:** ________April 17, 2007_________________________
4. **Submitter:** ________Pat Longshore____________________
5. **Phone No.** _________803-217-7490____________________

1. Exciter Information:

Manufacturer: __________Basler_______________________

Type of Excitation System:

- [X] Static
- [ ] Brushless
- [ ] Alternator Rectifier
- [ ] Motor Driven dc exciter
- [ ] Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: ___________________________________

Type of Voltage Regulator:

- [ ] Analog
- [X] Digital
- [ ] Other(describe)
- [ ]

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes_______ No__X__

If the answer is yes,

Manufacturer: ___________________________________

Type of PSS:

- [ ] Single input (delta speed/frequency type)
- [ ] Dual input (integral of accelerating power)
- [ ] Other(describe)
- [ ]

Attachment 2

Reporting Form

Excitation Systems Controls

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2.

6. Provide the data required in III.G.2 on Excitation Limit Controls.

Notes:

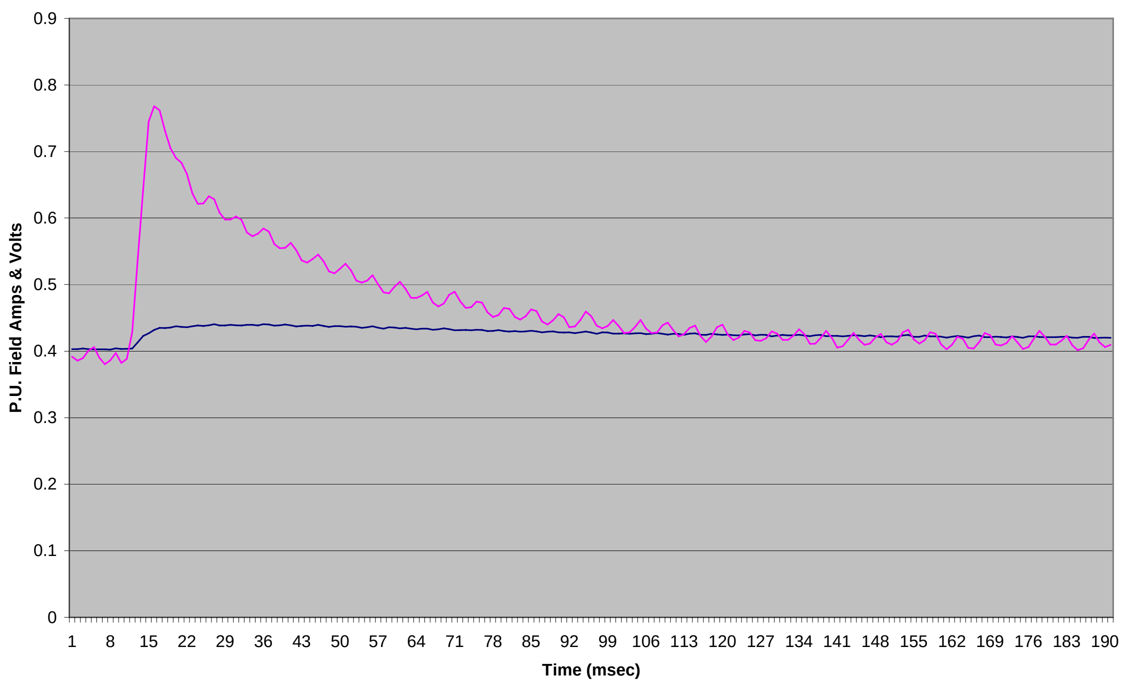
1. I obtained the IEEE exciter model from the vendor, along with the gains and constants. Our Transmission Planner (TP) performed the simulation and we did not get good correlation. The TP recommended a change to a constant and asked me to check with the Vendor. The Vendor agreed to the change and also recommended one more change to a constant. After a couple of iterations, we obtained good correlation between the model and the step response test.

Attachment 2

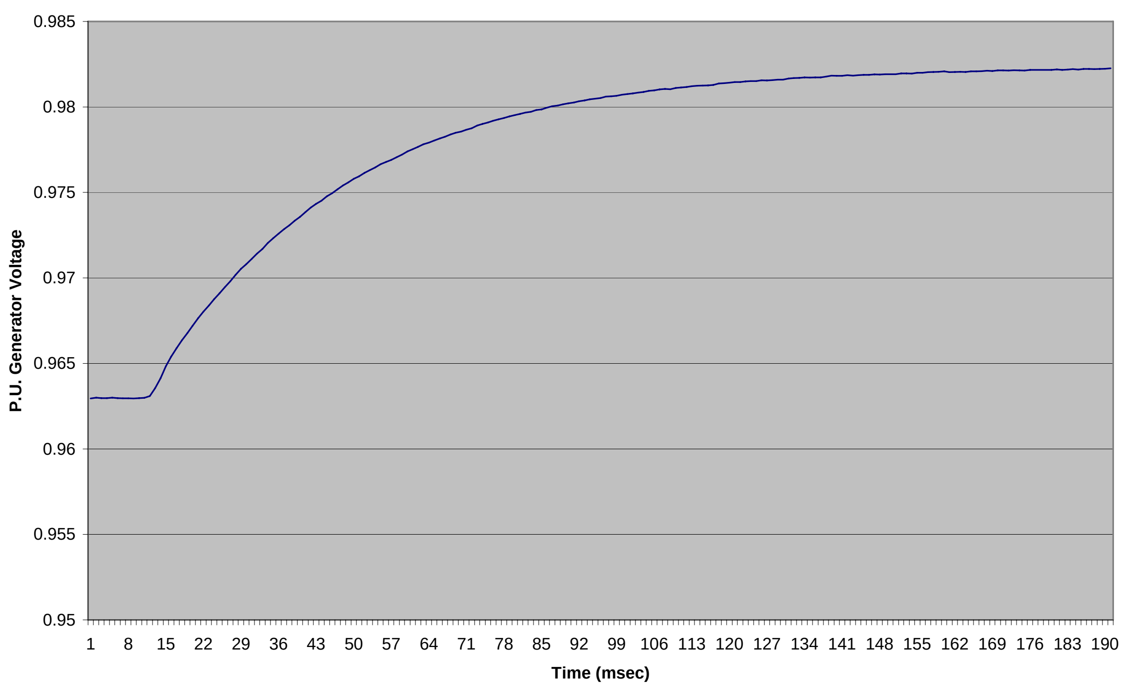
Reporting Form

Excitation Systems Controls

Canadys #2 - 2% OCSR - Field Amps & Volts



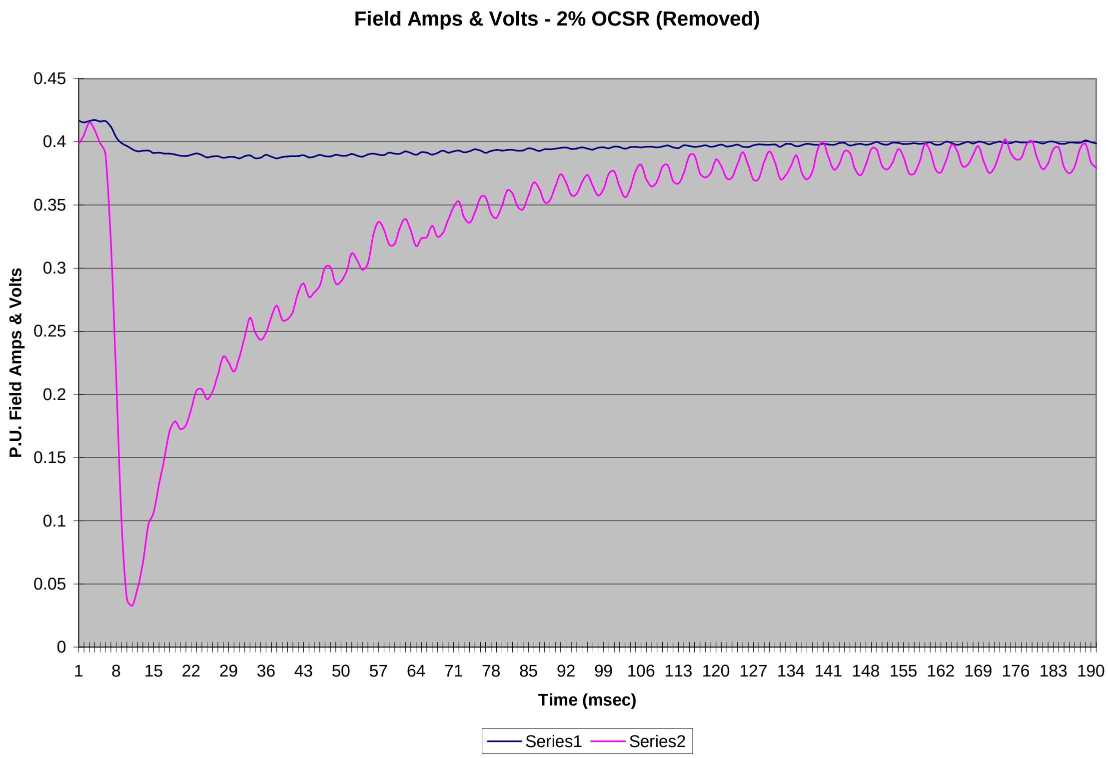
Canadys #2 - 2% OCSR (Gen. Volts)

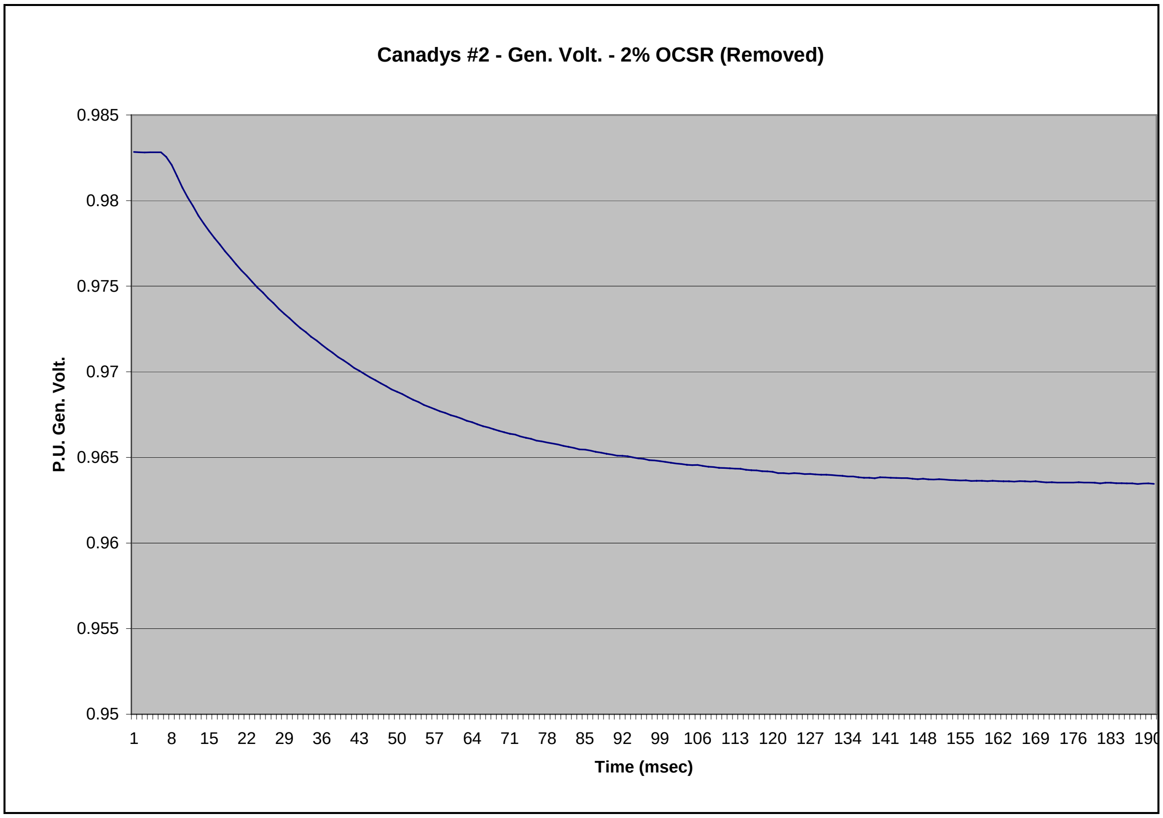


Attachment 2

Reporting Form

Excitation Systems Controls





SCG Unit
MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : ____1___ Hours
   - Setup of Test Equipment:_____1____ Hours
   - Time to Prepare Unit for Test: __0.5____ Hours
   - Performance of Test and Data Collection: ___0.5___ Hours
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? ___8.0_____ Hours.
3. Was a good correlation between the exciter model and the OCSR test obtained? (**Yes** or No) The correlation of the field test data and the modeling data has been a time consume process for the subject system. We are currently finalizing the correlation by applying the IEEE AC7B model.

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? _2% of nominal____________
5. List any material costs associated with this testing.

   ____
   ____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (**Yes** or No). If no, please attach additional information as appropriate.

   The set points were verified using simulated signals into the Exc. System.
7. Please list any suggested changes to the guideline?

   ____
   ____
   ____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026). See below.

SCG Unit
MOD-026 SERC Field Test Reporting Form

9. Name of the person completing the form:_Tom Higgins_______

Phone Number 205-992-7162____

Company Name_Southern Company Services____________

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

SCG Unit
MOD-026 SERC Field Test Reporting Form

Attachment 2:

1. **Unit Name: Sample Unit**
2. **Company: Southern Company Generation**
3. **Date: 06 Mar 2007**
4. **Submitter: William D. Shultz**
5. **Phone No. 877-335-5753**

1. Exciter Information:

Manufacturer: ____________________

Type of Excitation System:

	Static
	Brushless
x	Alternator Rectifier
	Motor Driven dc exciter
	Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: ____________________

Type of Voltage Regulator:

	Analog
x	Digital
	Other(describe)

SCG Unit
MOD-026 SERC Field Test Reporting Form

Attachment 2:

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes______ No__**x**__

If the answer is yes,

Manufacturer: ________________________________

Type of PSS:

	Single input (delta speed/frequency type)
	Dual input (integral of accelerating power)
	Other(describe)

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

Field Test Data:

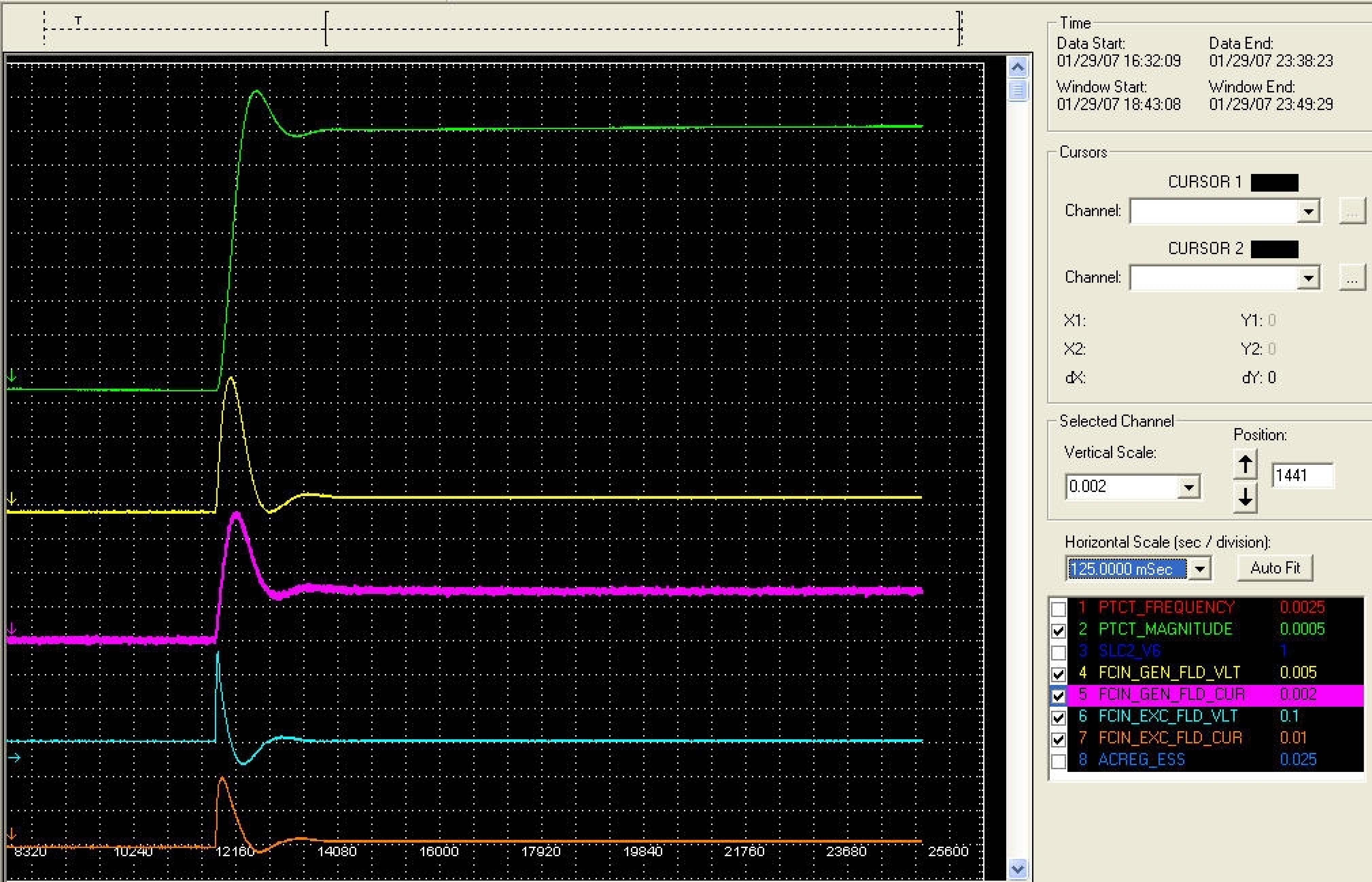
gs5 2pct step 29 Jan 2007.jpg ...

Model Validation Study Results:

SCG Sample Excitation System Mo

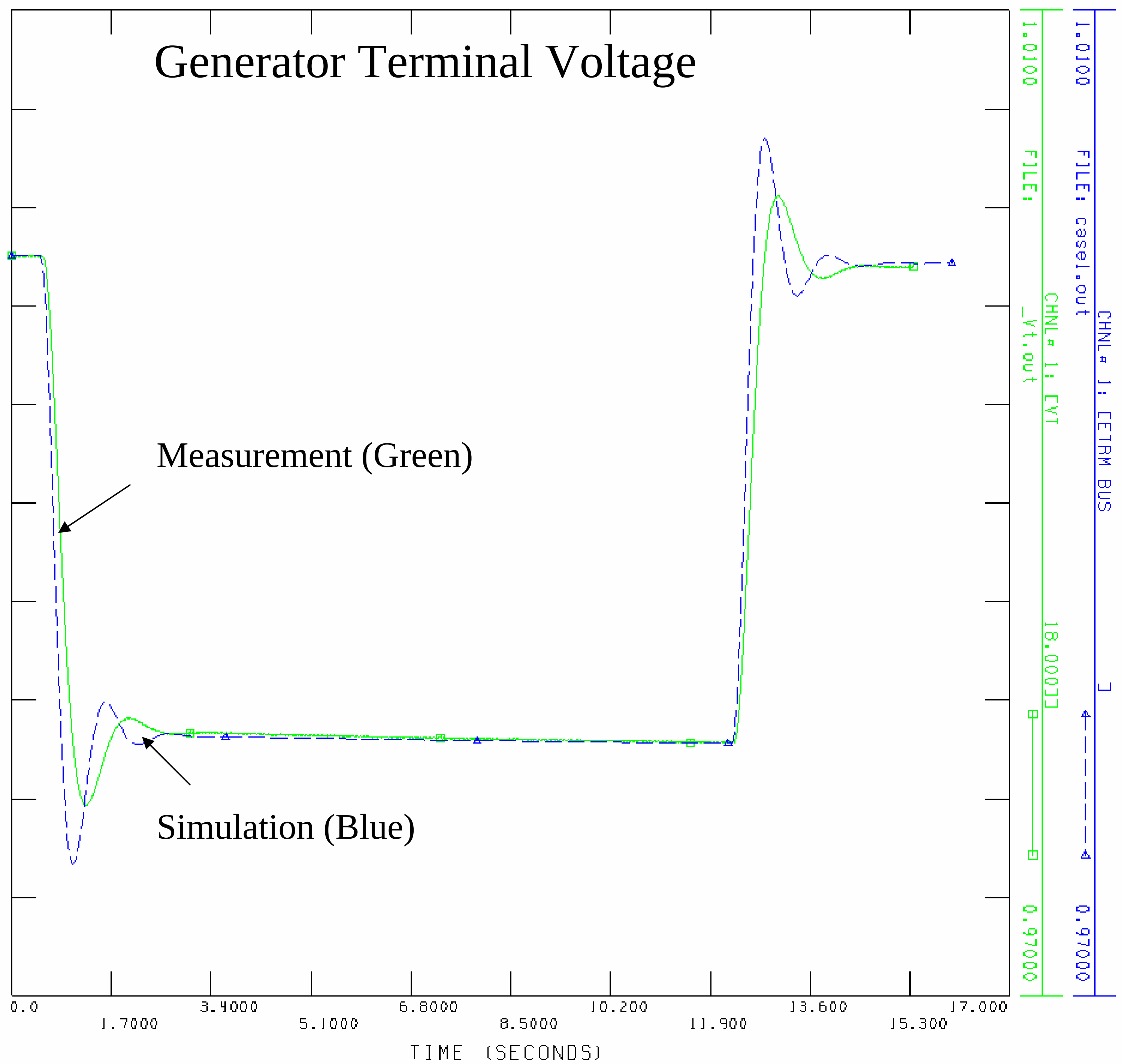
5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2. **N/A**

6. Provide the data required in III.G.2 on Excitation Limit Controls. Data is available upon request**. The coordination curves for this unit are contained in SCG's response to PRC-019. Actual field settings corresponded to these curves.**

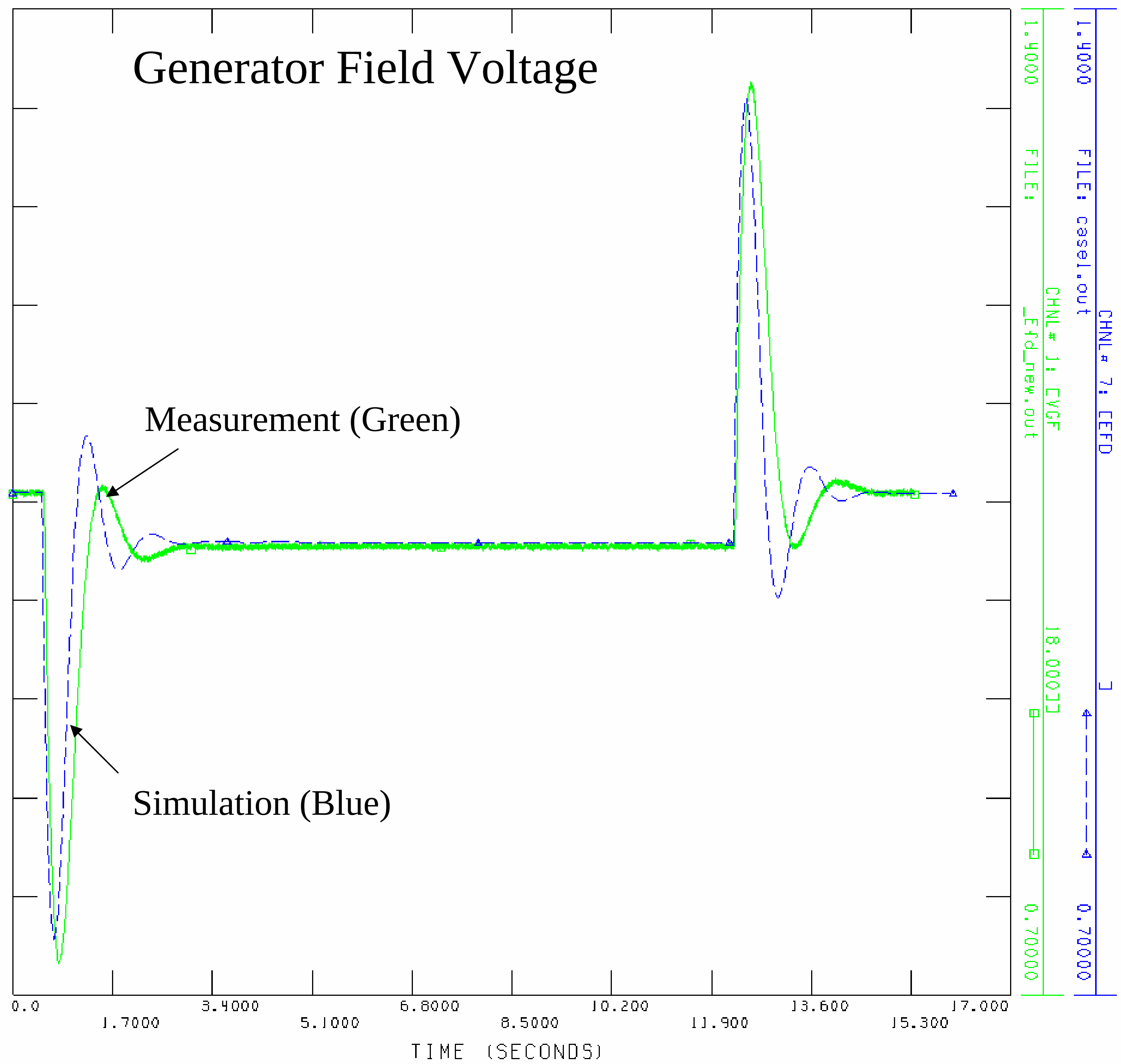

T
8320
10240
12160
14080
16000
17920
19840
21760
23680
25600
Time
Data Start:
01/29/07 16:32:09
Data End:
01/29/07 23:38:23
Window Start:
01/29/07 18:43:08
Window End:
01/29/07 23:49:29
Cursors
CURSOR 1
Channel:
CURSOR 2
Channel:
X1:
Y1: 0
X2:
Y2: 0
dX:
dY: 0
Selected Channel
Vertical Scale:
0.002
Position:
1441
Horizontal Scale (sec / division):
125.0000 mSec
Auto Fit
1 PTCT_FREQUENCY 0.0025
2 PTCT_MAGNITUDE 0.0005
3 SLC2_V6 1
4 FCIN_GEN_FLD_VLT 0.005
5 FCIN_GEN_FLD_CUR 0.002
6 FCIN_EXC_FLD_VLT 0.1
7 FCIN_EXC_FLD_CUR 0.01
8 ACREG_ESS 0.025

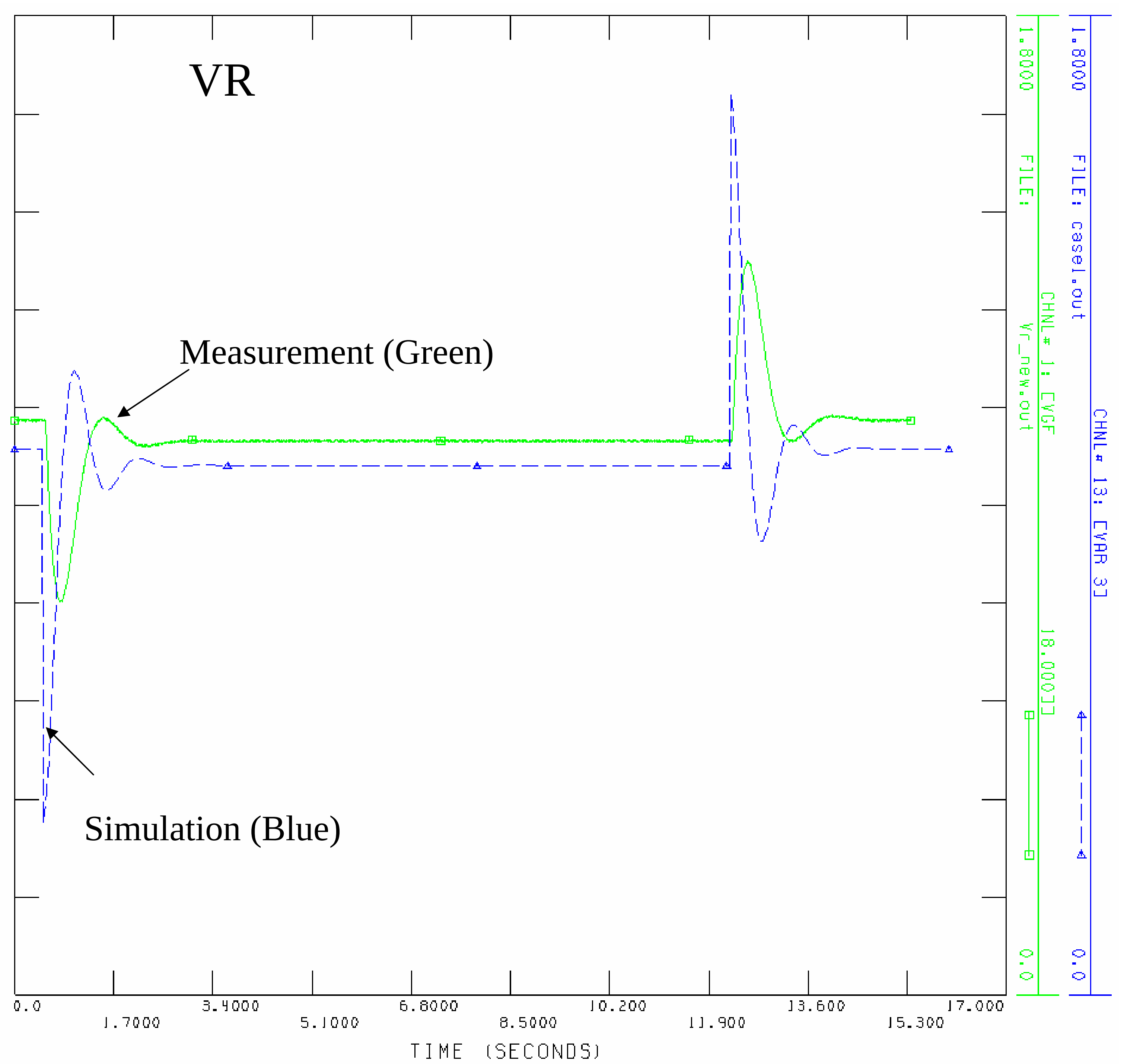
SCG Excitation System Model/Parameter Validation for Sample Unit

For SERC Field Test of MOD-026



Generator Terminal Voltage
Measurement (Green)
Simulation (Blue)
0.0
1.7000
3.4000
5.1000
6.8000
8.5000
10.200
11.900
13.600
15.300
17.000
TIME (SECONDS)
1.0100
FILE: _Vt.out
CHNL# 1: [VT
18.0000]
0.97000
1.0100
FILE: case1.out
CHNL# 1: [ETRM BUS
1]
0.97000


Generator Field Voltage
Measurement (Green)
Simulation (Blue)
0.0
1.7000
3.4000
5.1000
6.8000
8.5000
10.200
11.900
13.600
15.300
17.000
TIME (SECONDS)
1.4000
FILE: _Efd_new.out
CHNL# 1: [VGF
18.000]
0.70000
1.4000
FILE: case1.out
CHNL# 7: [EFD
1]
0.70000


VR
Measurement (Green)
Simulation (Blue)
1.8000
FILE:
Vr_new.out
CHNL# 1: [VGF
18.000]
0.0
1.8000
FILE: case1.out
CHNL# 13: [VAR 3]
0.0
0.0
1.7000
3.4000
5.1000
6.8000
8.5000
10.200
11.900
13.600
15.300
17.000
TIME (SECONDS)

Attachment 4
MOD-027 Test Results

- **DVP_SERC MOD-027 Field Test Reporting Form 061207.doc**
- **DVP_SERC MOD-027 Field Test RF-Item 3B Details 061207.doc**
- **DVP_Unit A_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit B_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit C_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit E_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit F_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit G_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Simulation_Plots_for_Both_Events_061207.pdf**
- **SERC Nelson u4-MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **nelson u4-attachment2.doc**
- **SERC wbluff u1-MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **wbluff u1-attachment2.doc**
- **SERC wbluff u2-MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **white bluff u2-attachmnet2.doc**
- **entergy-Mod-027Simulation-Results.ppt**
- **serc mod-027 field test reporting form rev 0 (4-17-07)(Completed).doc**
- **SCG MOD-027 Field Test Reporting Form.doc**
- **SoGenUnits_Response_WansleyTrips_Sanatized_Final.ppt**

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) No
   - If yes, what is the maintenance interval? (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) No
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) No

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? (hours)
   - How long did it take to set up the model to simulate this event? (hours)
   - How long did it take to compare the generator output data to the model? (hours)
   - Did the model parameters or type need to be changed?

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study. None
5. Please list any suggested changes to the guideline? Most model/parameters available for the turbine-governor control systems are estimated or typical at best (this is more likely an Industry wide concern). Initially, it might be worth to have initially a couple of units field tested for the accuracy of the model/parameters. Once such field test is performed and the model and parameters are validated, then it might provide a better judgment of whether this Field Test Method provides meaningful and consistent comparison between recorded data and the simulated test results for an event or not.
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Kirit Doshi Phone Number: 804-819-2322
   Company Name: Dominion Virginia Power

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

Dominion Explanation
Ref. MOD-027 SERC Field Test Reporting Form, Item 3B

The table below compares field observed readings (from SCADA/EMS data) with the simulation test results for six Dominion (F&H) units for the Wansley and the Oconee trip events. If we consider the difference within 1% of Pmax as acceptable, six instances out of total 12 matches reasonably well as far as the MW pick-up amount is concerned. Out of these six, four are for the Wansley event and two are for the Oconee event.

Field Observations Over a 60-Second Period (Maximum reading within this range used for each unit)

Dominion Unit ID	Pmax (MW)	Pre-Event Load (MW)	Max Observed Pick-up within 60 seconds (MW)	Simulated Pick-up MW	Simulated Pick-up % of Pmax	Difference between Pmax and Pgen	MW Diff. in Response (Simulated minus Observed)	Difference as % of Pmax
A	71	62.40	0.18	1.89	2.66	8.60	1.71	2.41
		55.38	0.96	1.88	2.65	15.62	0.92	1.30
B	118	97.48	1.45	3.29	2.79	20.52	1.84	1.56
		100.80	2.52	3.29	2.79	17.20	0.77	0.65
C	103	88.34	0.65	3.04	2.95	14.66	2.39	2.32
		79.92	2.81	3.04	2.95	23.08	0.23	0.22
D								
E	464	454.13	0.75	5.05	1.09	9.87	4.30	0.93
		457.50	0.75	3.64	0.78	6.50	2.89	0.62
F	110	81.32	1.40	2.67	2.43	28.68	1.27	1.15
		99.36	0.88	2.70	2.45	10.64	1.82	1.65
G	170	170.75	0.63	0.71	0.42	(0.75)	0.08	0.05
		169.75	1.00	1.26	0.74	0.25	0.26	0.15

Blue color readings are for Oconee event

Red color readings are for Wansley event

Note: Unit D was later deleted from the test upon finding that this unit is not expected to respond.

As for the MW versus Time comparison, below listed data indicates the recorded elapsed time in seconds from the initiation of each event for each unit to reach the maximum MW pick-up within the observed time range of 60 seconds.

	(a) Wansley Event	(b) Oconee Event
Unit A:	21	20
Unit B:	42	26
Unit C:	35	20
Unit E:	13	18
Unit F:	19	12
Unit G:	19	44

The simulated responses for most cases indicated 85 to 90 % of the total MW pick-up occur in the first 5 to 7 seconds and then gradually creep up over the next 30 to 50 seconds. Overall, the match between the field-observed responses and the simulated responses are less than satisfactory for the units tested.

This is not to say that the field test method developed is wrong. Most models/parameters available for the turbine-governor control systems are estimated or typical at best (this is more likely an Industry wide issue). Initially, it might be worth to have a couple of units field tested for the accuracy of simulation models/parameters and then evaluating this method of Field Testing may provide more accurate evaluation.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit A**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	____________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit B**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	____________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit C**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	____________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit E**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	____________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit F**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

x	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
	Digital electro-hydraulic (DEH)
	___________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit G**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

x	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
	Digital electro-hydraulic (DEH)
	______________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

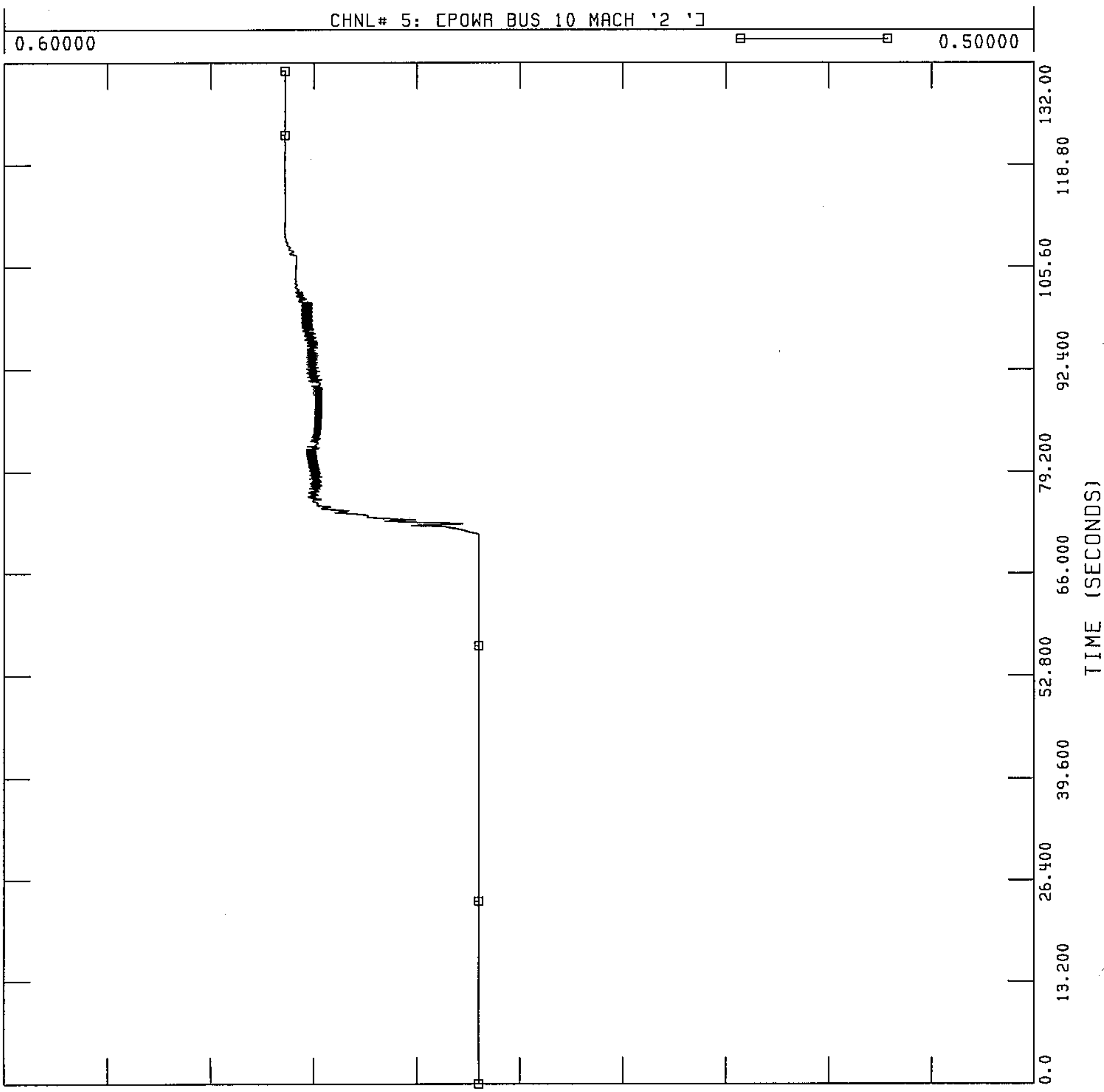
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven\[redacted]_WanTrip.OUT

FRI, JUN 08 2007 14:38

Wansley - A



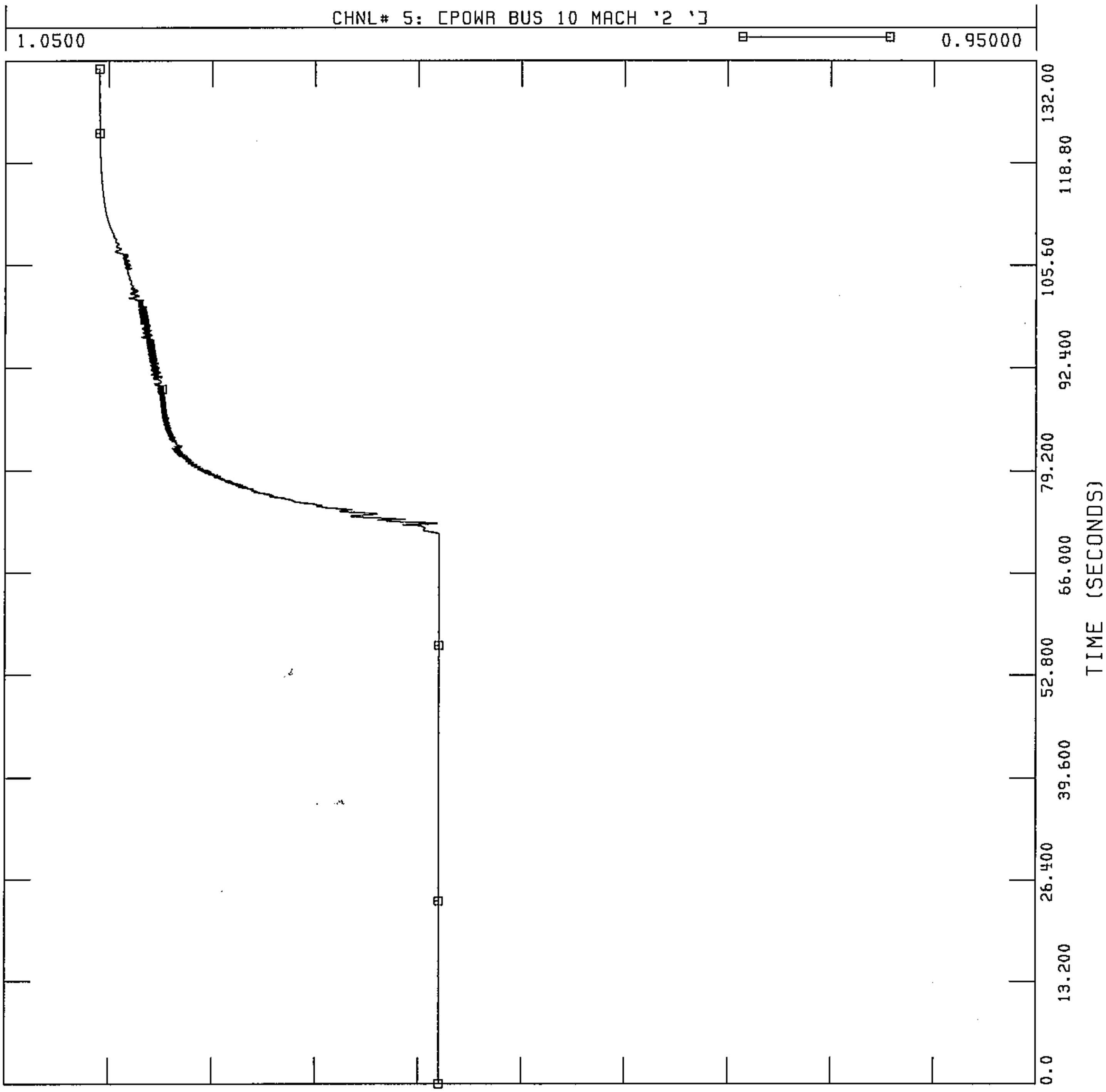
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven[redacted]_WanTrip.OUT

FRI, JUN 08 2007 14:37

Wansley - B

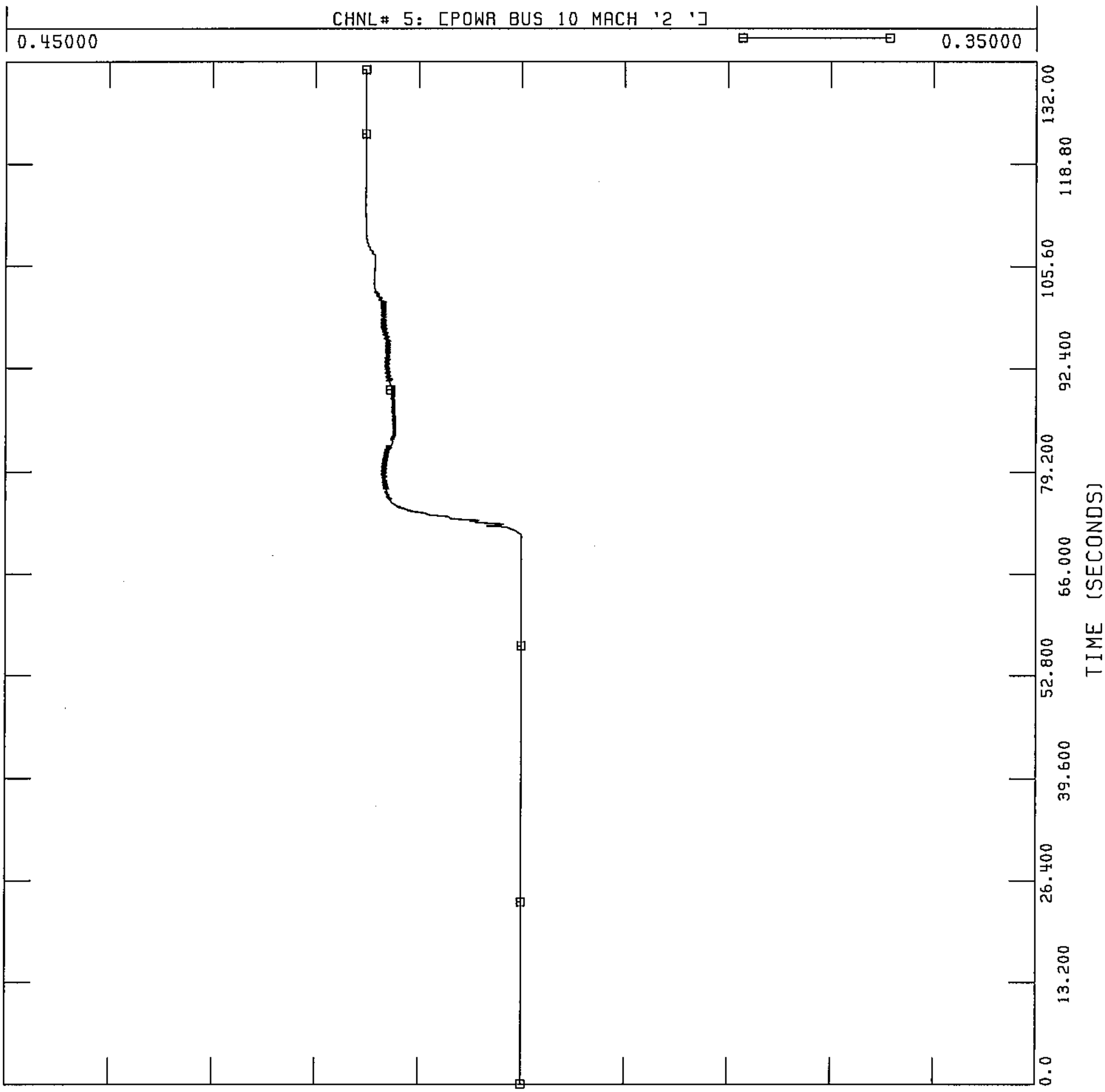


CASE WITH [redacted]AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven\[redacted]_WanTrip.OUT

FRI, JUN 08 2007 14:37

WANSLEY - C

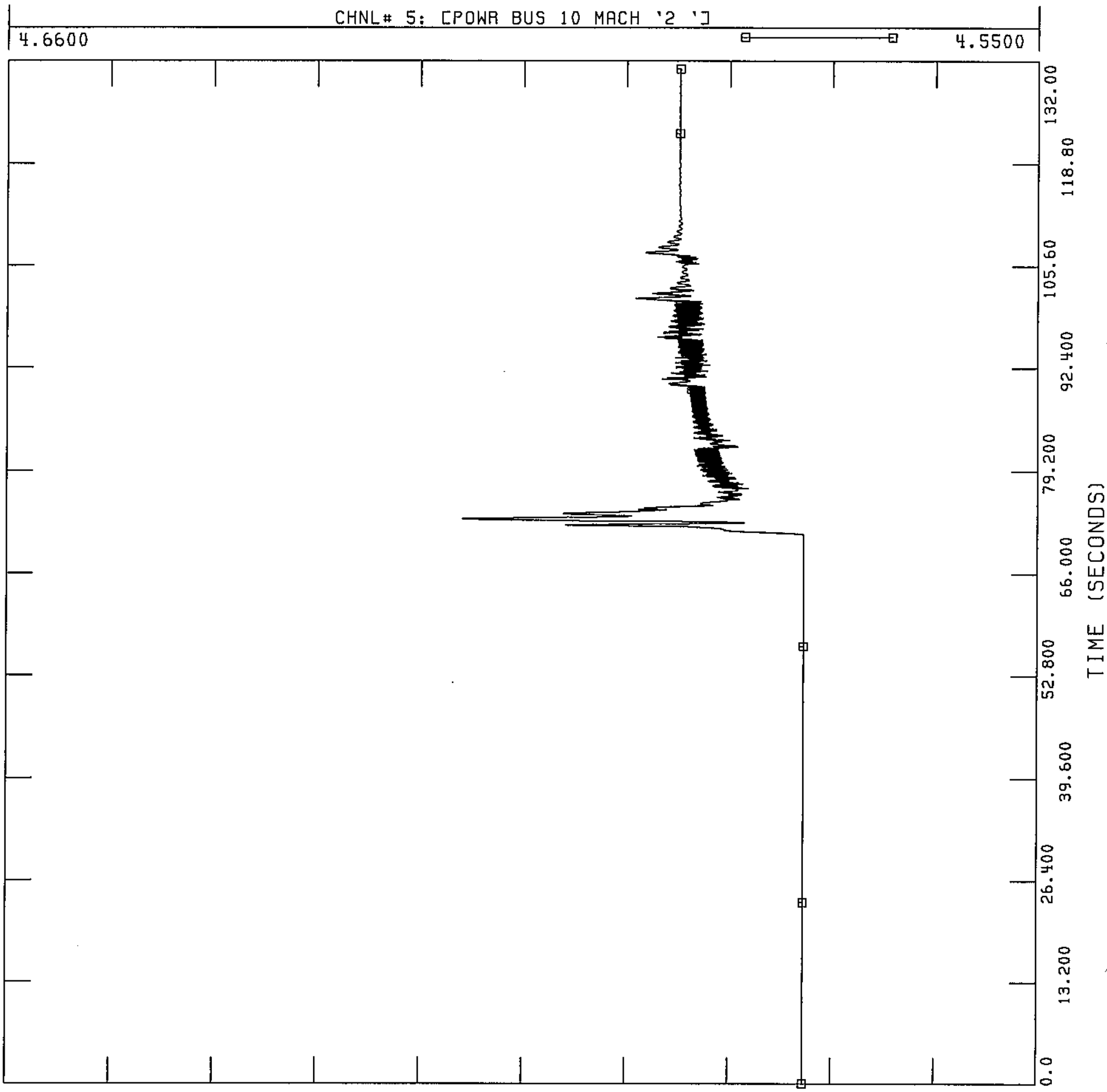


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven[redacted]WanTrip.OUT

FRI, JUN 08 2007 14:45

WANSLEY-E



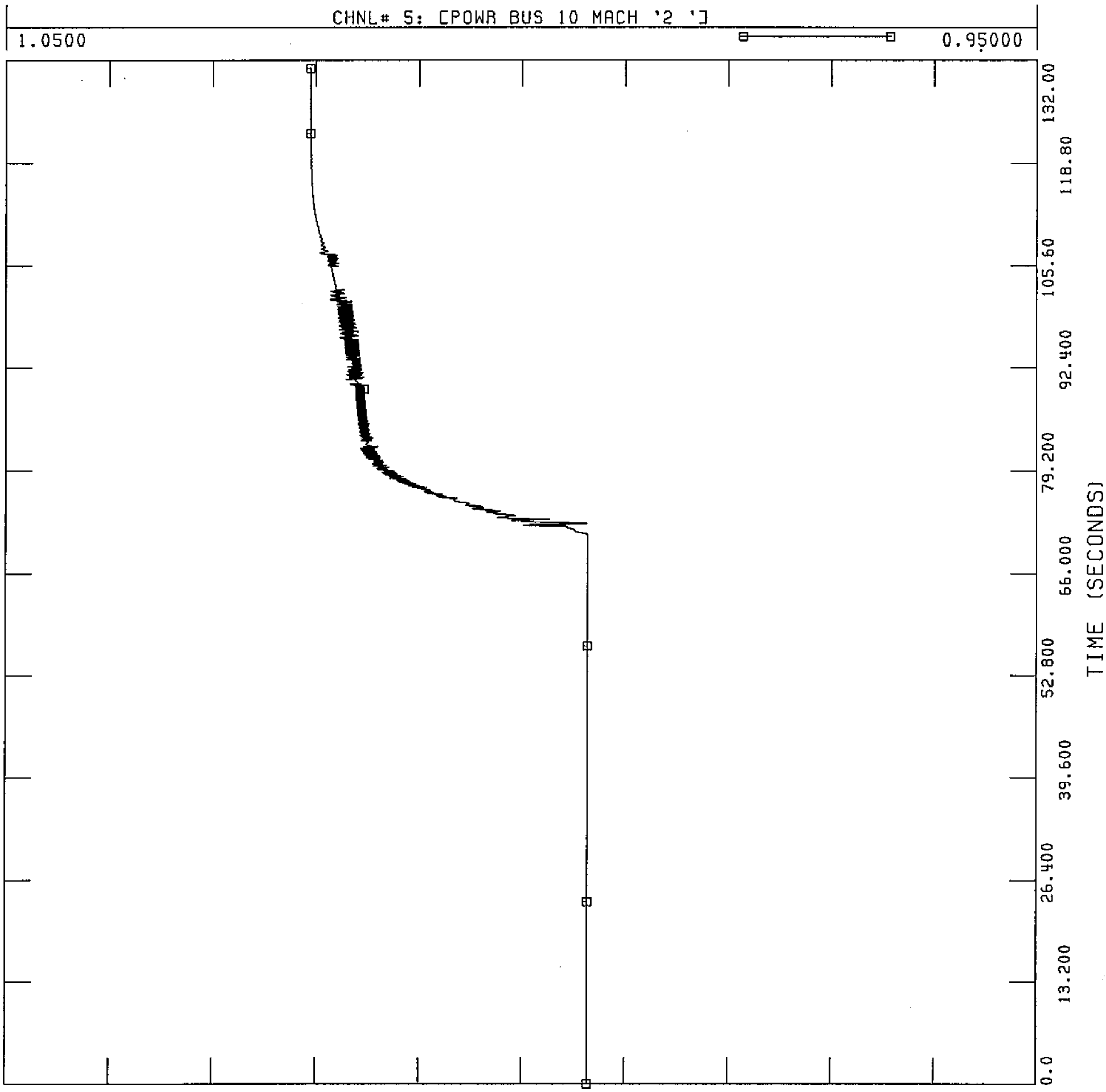
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven[redacted]anTrip.OUT

FRI, JUN 08 2007 14:29

WANSLEY - F



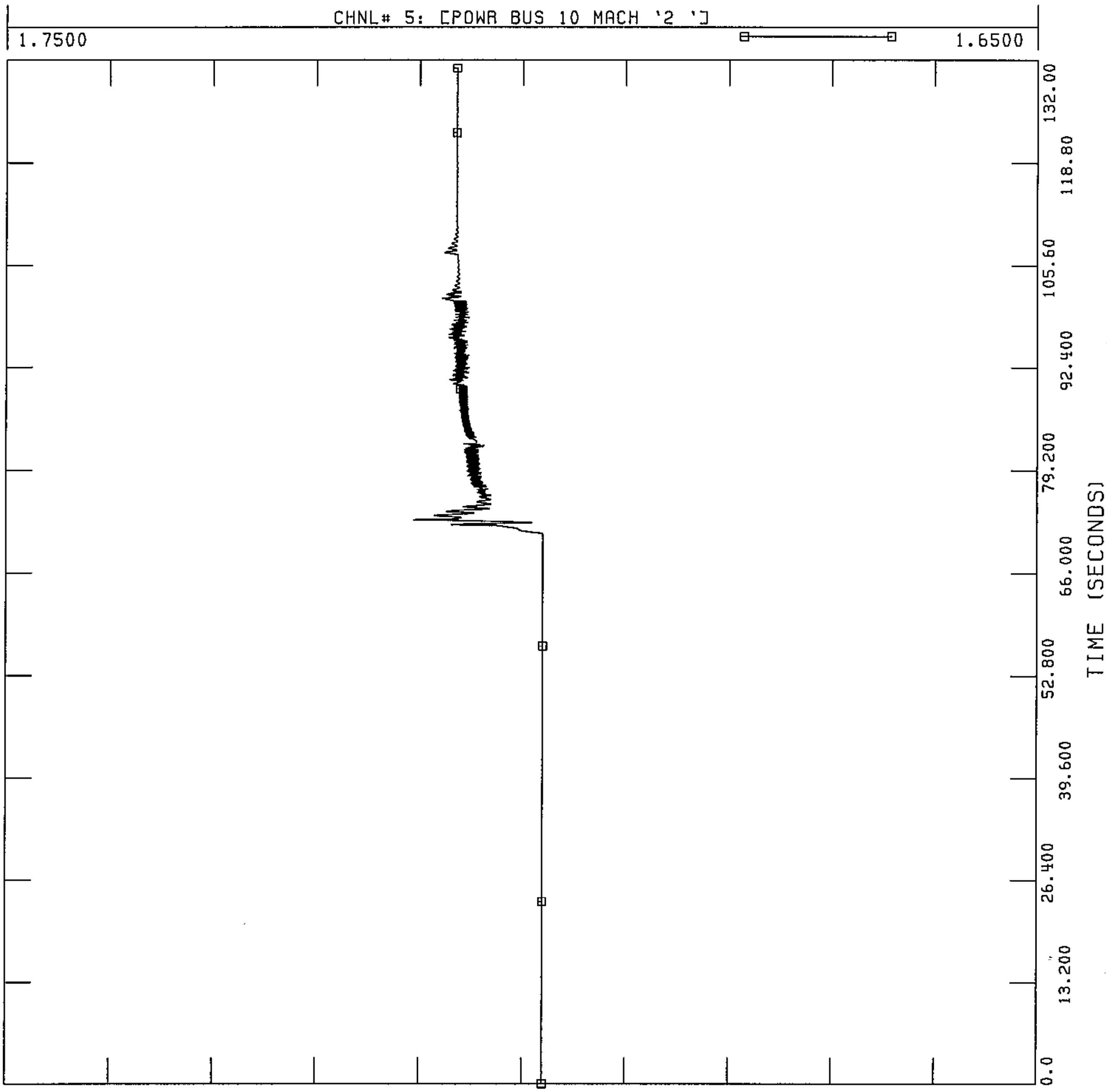
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted]AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven[redacted]WanTrip.OUT

FRI, JUN 08 2007 14:29

Wansley - G



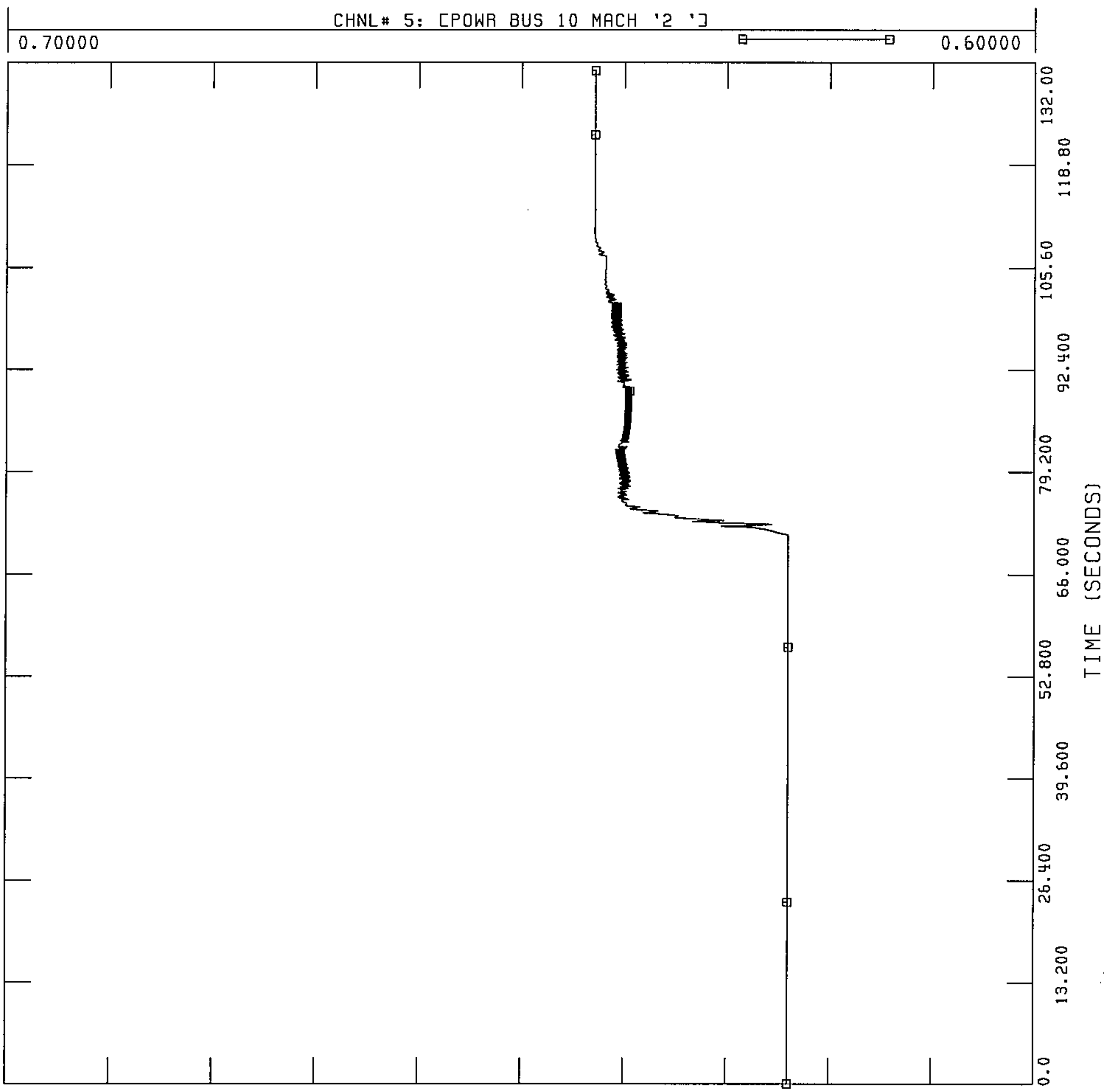
CASE WITH [redacted] AS TEST MACHINE

SIEMENS POWER TECHNOLOGIES INTERNATIONAL

FILE: C:\doshi\AAOconee\Seven\[redacted]_OconTrip.OUT

FRI, JUN 08 2007 14:27

Oconee - A



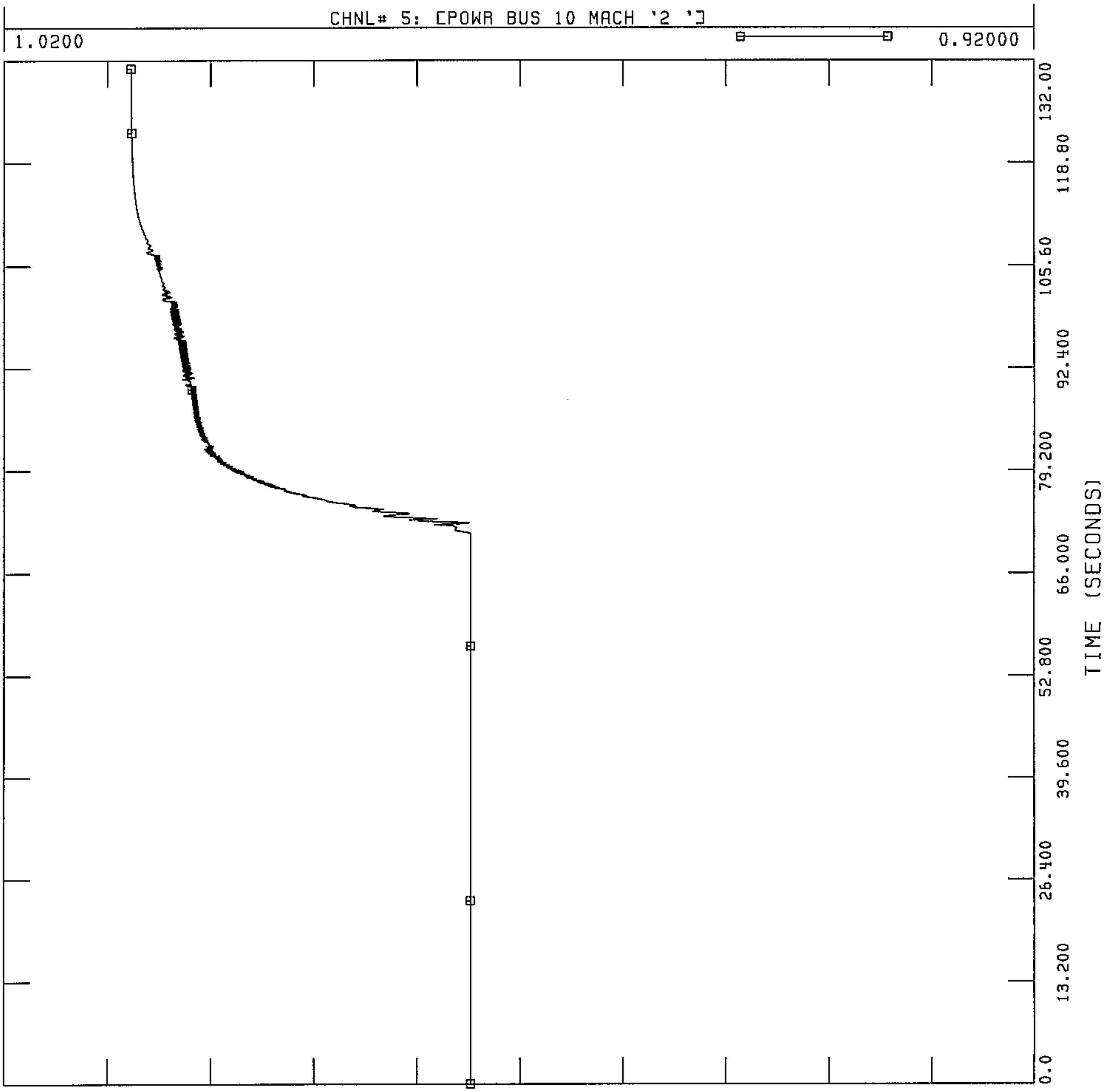
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven\[redacted]OconTrip.OUT

FRI, JUN 08 2007 14:25

Oconee - B



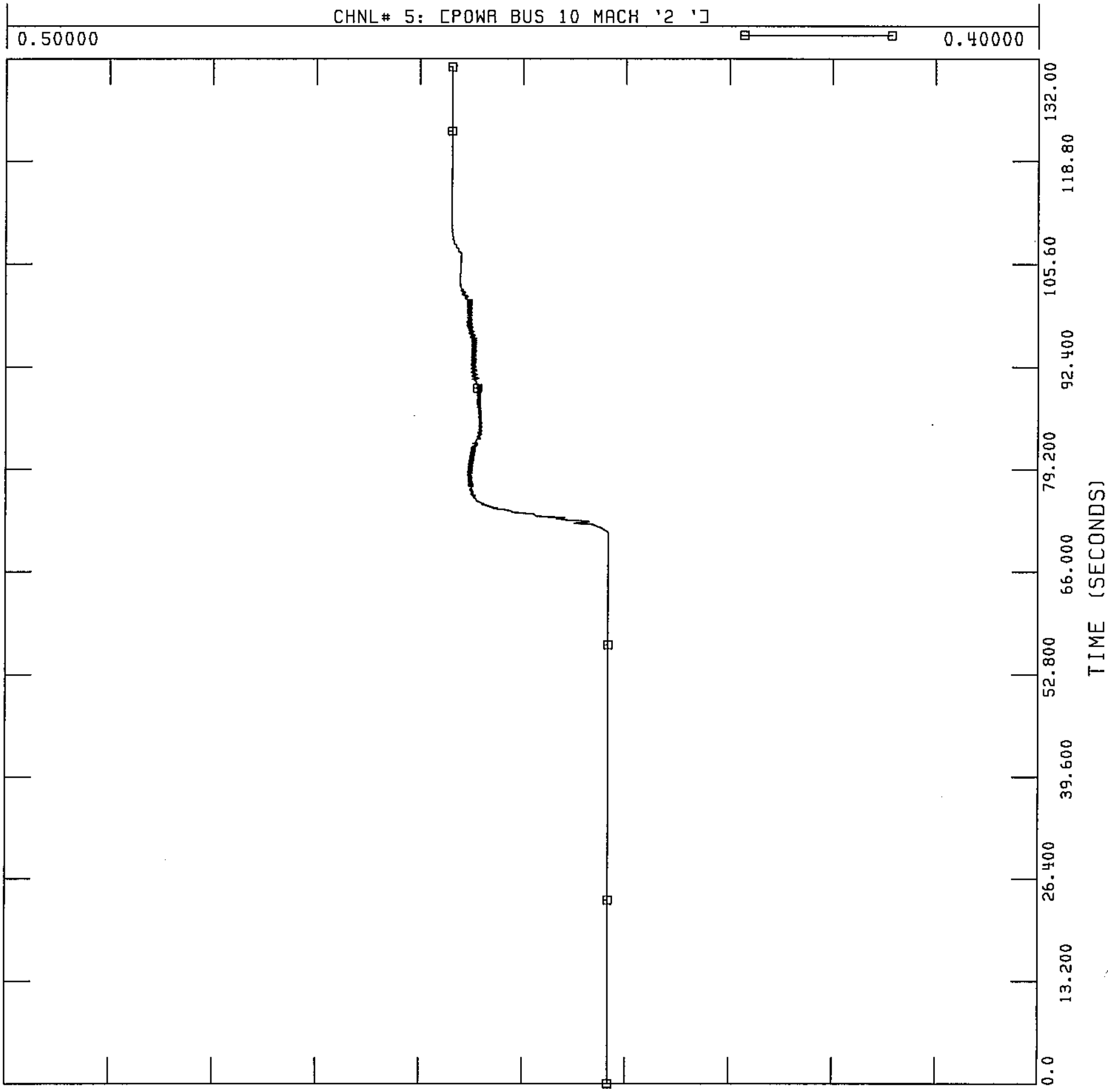
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted] 1 AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven\[redacted]_OconTrip.OUT

FRI, JUN 08 2007 14:26

OCONEE - C



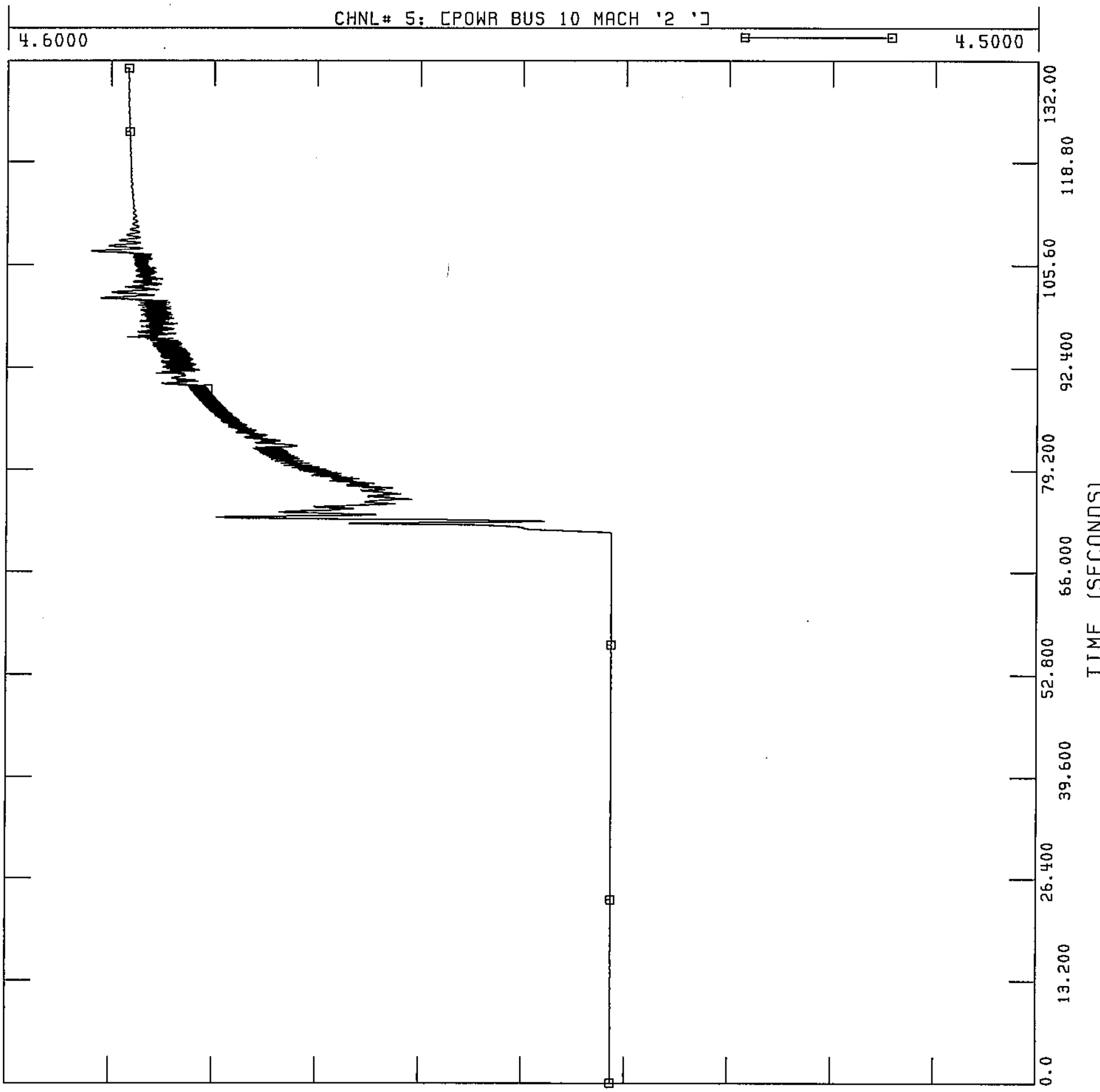
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven\[redacted]_OconTrip.OUT

FRI, JUN 08 2007 14:47

OCONEE - E



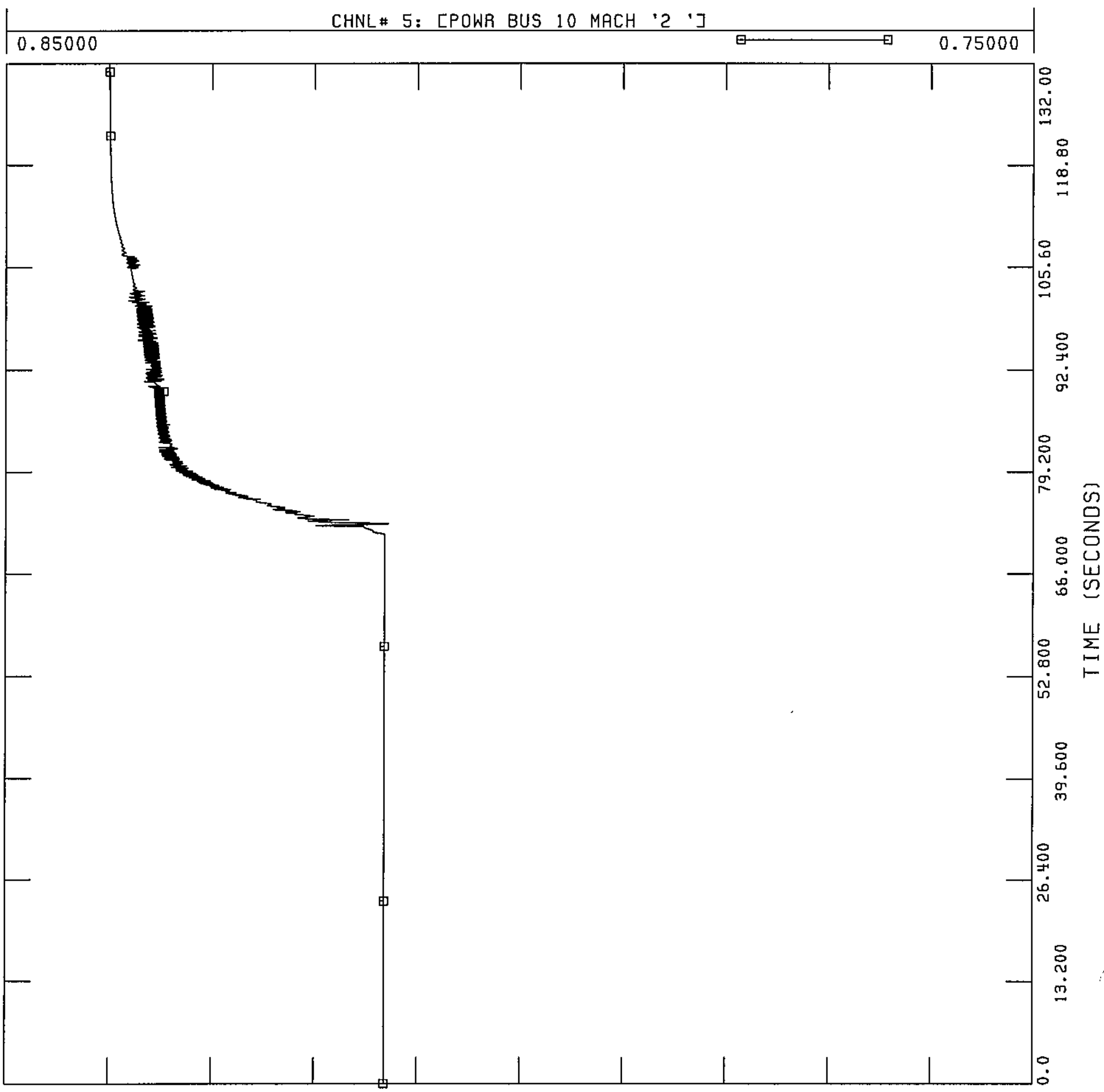
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven[redacted]OconTrip.OUT

FRI, JUN 08 2007 14:24

OCONEE - F



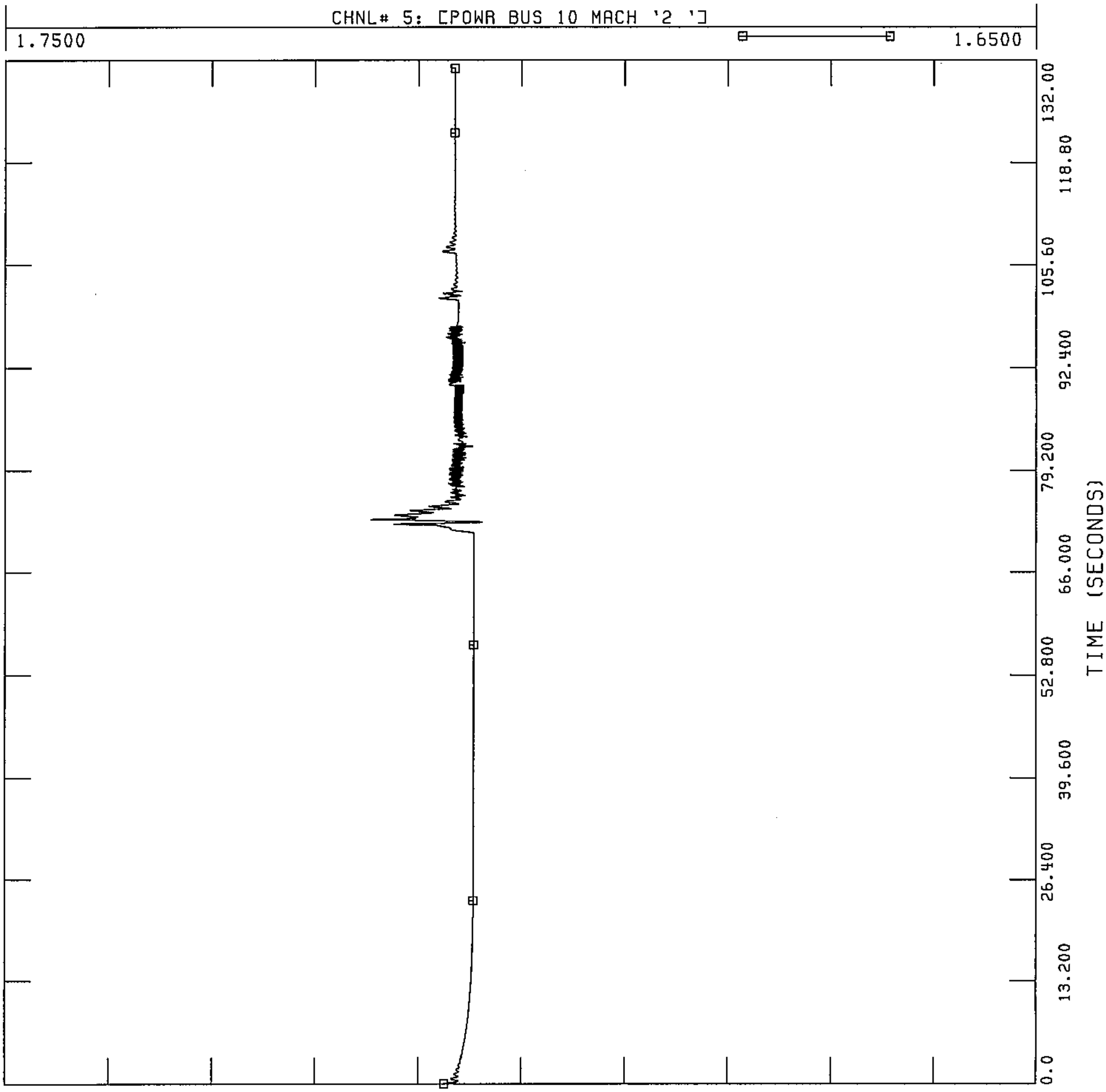
SIEMENS POWER TECHNOLOGIES INTERNATIONAL

CASE WITH [redacted]S TEST MACHINE

FILE: C:\doshi\AAOconee\Seven\[redacted]OconTrip.OUT

FRI, JUN 08 2007 14:49

OCONEE-GT.



MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) yes
    - If yes, what is the maintenance interval? 84 (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) no
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) Yes

    3. A. **If yes:** (Use additional pages if needed to explain.)
    - How long did it take to obtain the generator output data? 1 (hours)
    - How long did it take to set up the model to simulate this event? 3 (hours)
    - How long did it take to compare the generator output data to the model? 1 (hours)
    - Did the model parameters or type need to be changed? no

    3. B. **If No:**
    - Use additional pages to explain.
4. List any material costs associated with this study. none
5. Please list any suggested changes to the guideline? none
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Sujit Mandal Phone Number: 504 576 2342 Company Name: Entergy

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: _Nelson Unit 4____________________________________**
2. **Company: _Entergy_______________________________________**
3. **Date: ___06/07/07____**
4. **Submitter: _Sujit Mandal____**
5. **Phone No. ___504 576 2342____________________________________**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	___________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ___5_________

MOD-027 SERC Field Test Reporting Form

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Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) yes
   - If yes, what is the maintenance interval? 84 (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) no
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) Yes

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? 1 (hours)
   - How long did it take to set up the model to simulate this event? 3 (hours)
   - How long did it take to compare the generator output data to the model? 1 (hours)
   - Did the model parameters or type need to be changed? no

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study. none
5. Please list any suggested changes to the guideline? none
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Sujit Mandal Phone Number: 504 576 2342 Company Name: Entergy

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: _White Bluff Unit 1_____________________________________**
2. **Company: _Entergy_______________________________________**
3. **Date: ___06/07/07____**
4. **Submitter: _Sujit Mandal_______________________________________**
5. **Phone No. ___504 576 2342_____________________________________**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	__________________________

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ___5_________

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) yes
   - If yes, what is the maintenance interval? 84 (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) no
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) Yes

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? 1 (hours)
   - How long did it take to set up the model to simulate this event? 3 (hours)
   - How long did it take to compare the generator output data to the model? 1 (hours)
   - Did the model parameters or type need to be changed? no

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study. none
5. Please list any suggested changes to the guideline? none
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Sujit Mandal Phone Number: 504 576 2342 Company Name: Entergy

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: _White Bluff Unit 2____________________________________**
2. **Company: _Entergy______________________________________**
3. **Date: ___06/07/07____**
4. **Submitter: _Sujit Mandal______________________________________**
5. **Phone No. ___504 576 2342____________________________________**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
x	Analog electro-hydraulic (EHC)
	Digital electro-hydraulic (DEH)
	___________________________

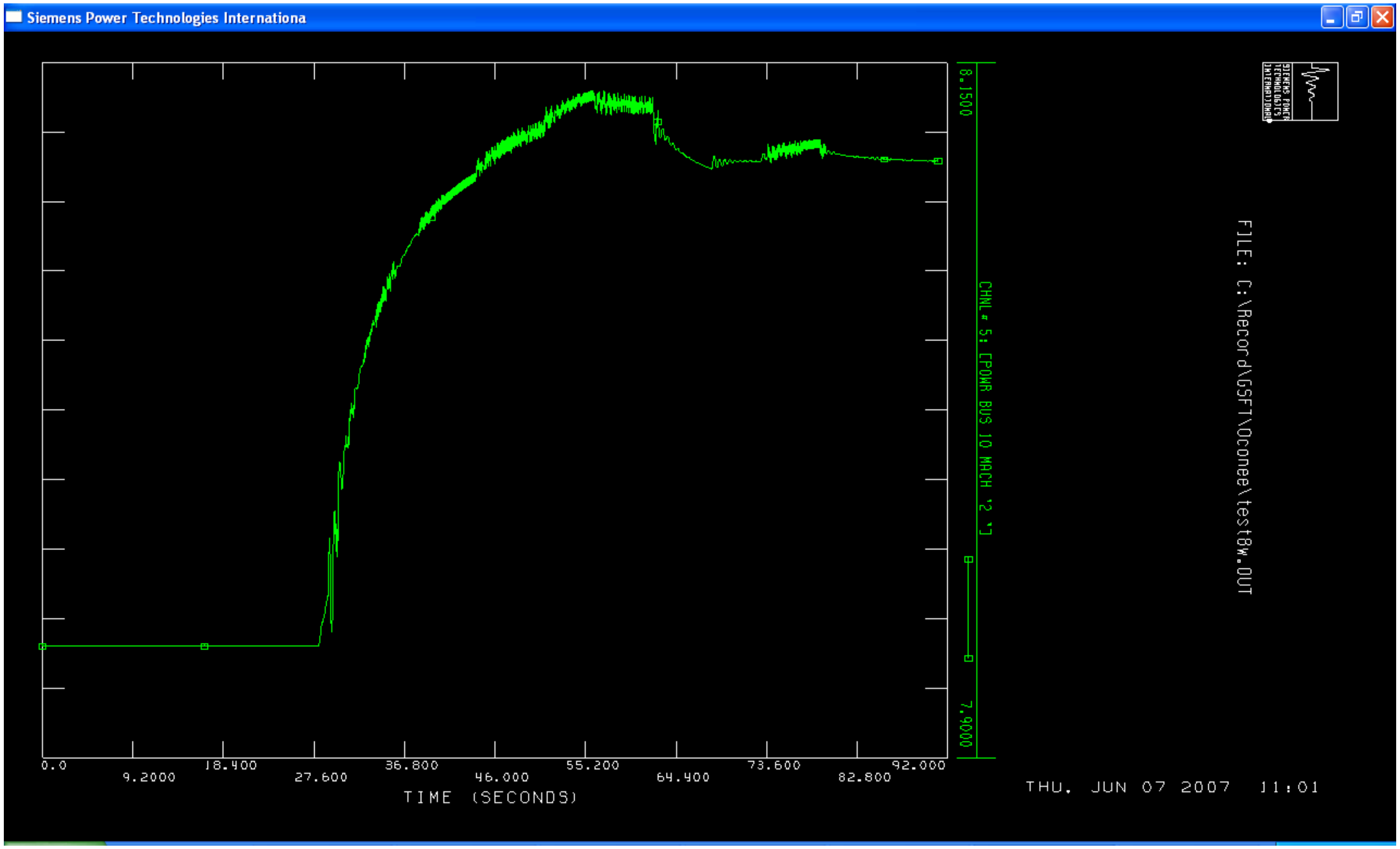
Check type of governor model submitted:

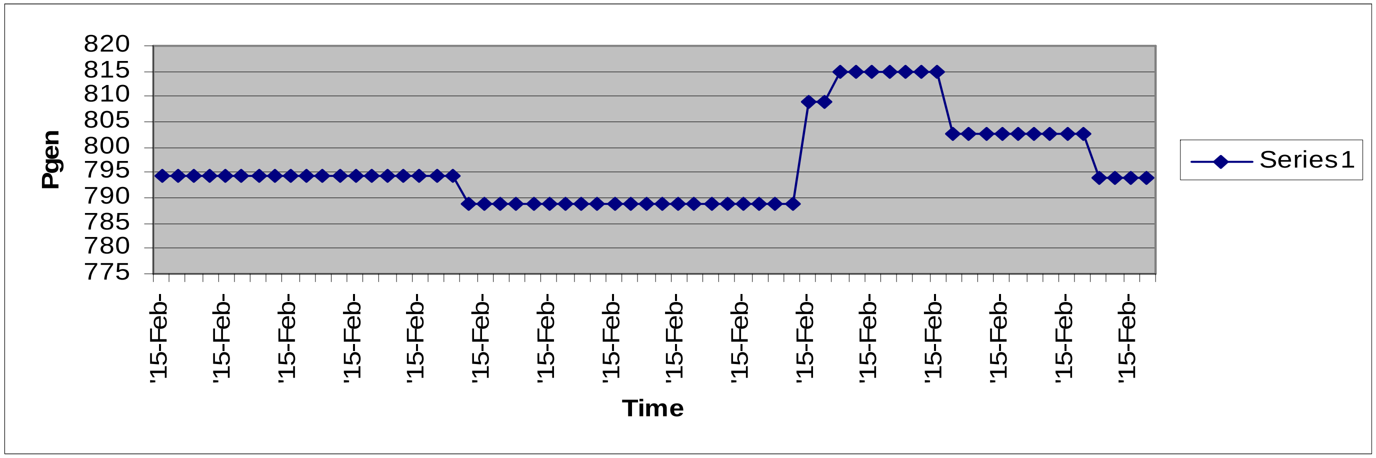
	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ___5_________

Oconee Event

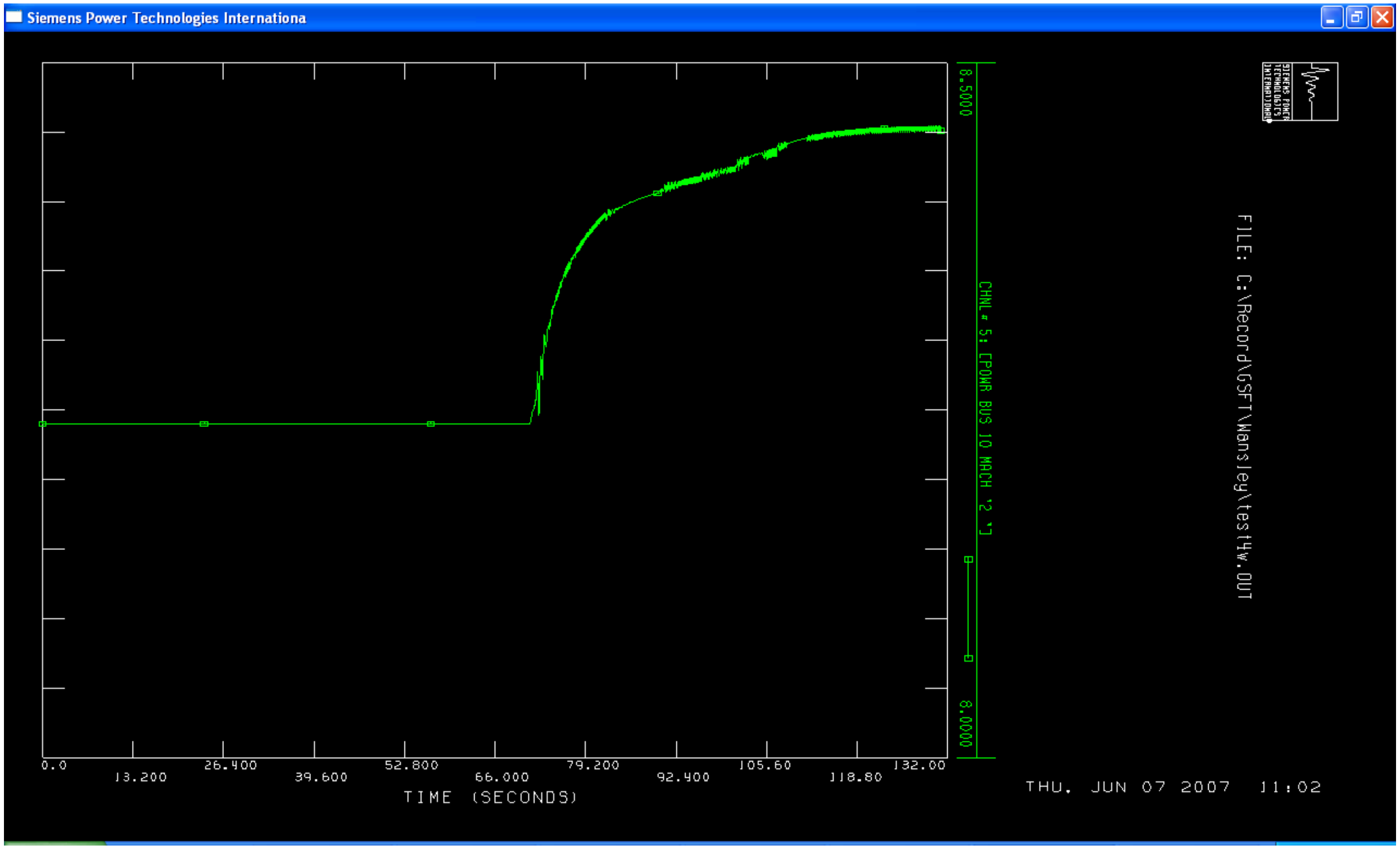
Simulation at White Bluff U1 (Coal fired)

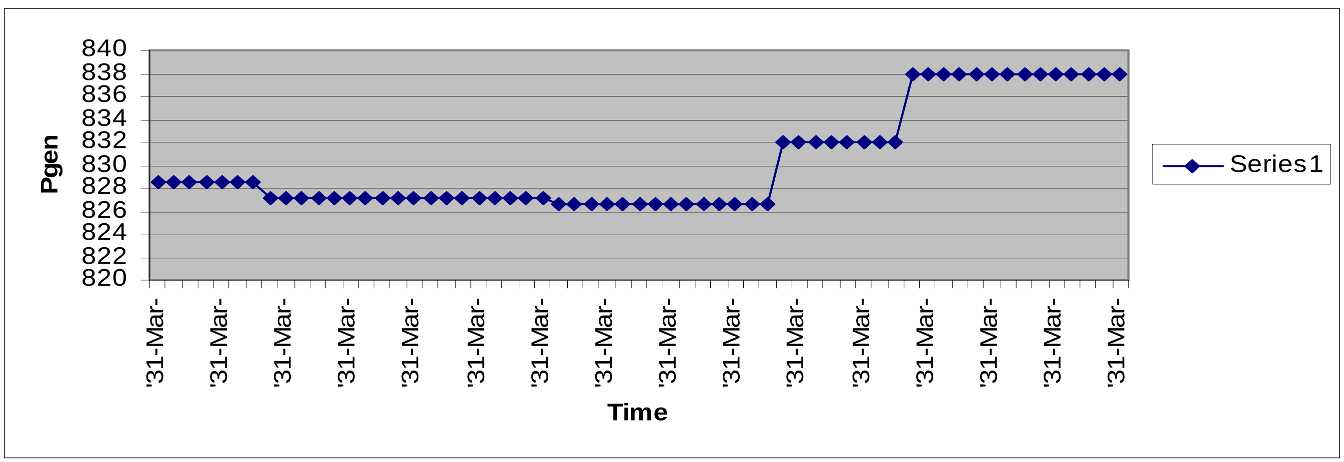

Siemens Power Technologies Internationa
8.1500
7.9000
CHNL # 5: [POWR BUS 10 MACH '2 ']
FILE: C:\Record\GSFT\Oconee\test8w.OUT
0.0
9.2000
18.400
27.600
36.800
46.000
55.200
64.400
73.600
82.800
92.000
TIME (SECONDS)
THU, JUN 07 2007 11:01


Pgen
820
815
810
805
800
795
790
785
780
775
'15-Feb-
Time
Series1

Wansley Event

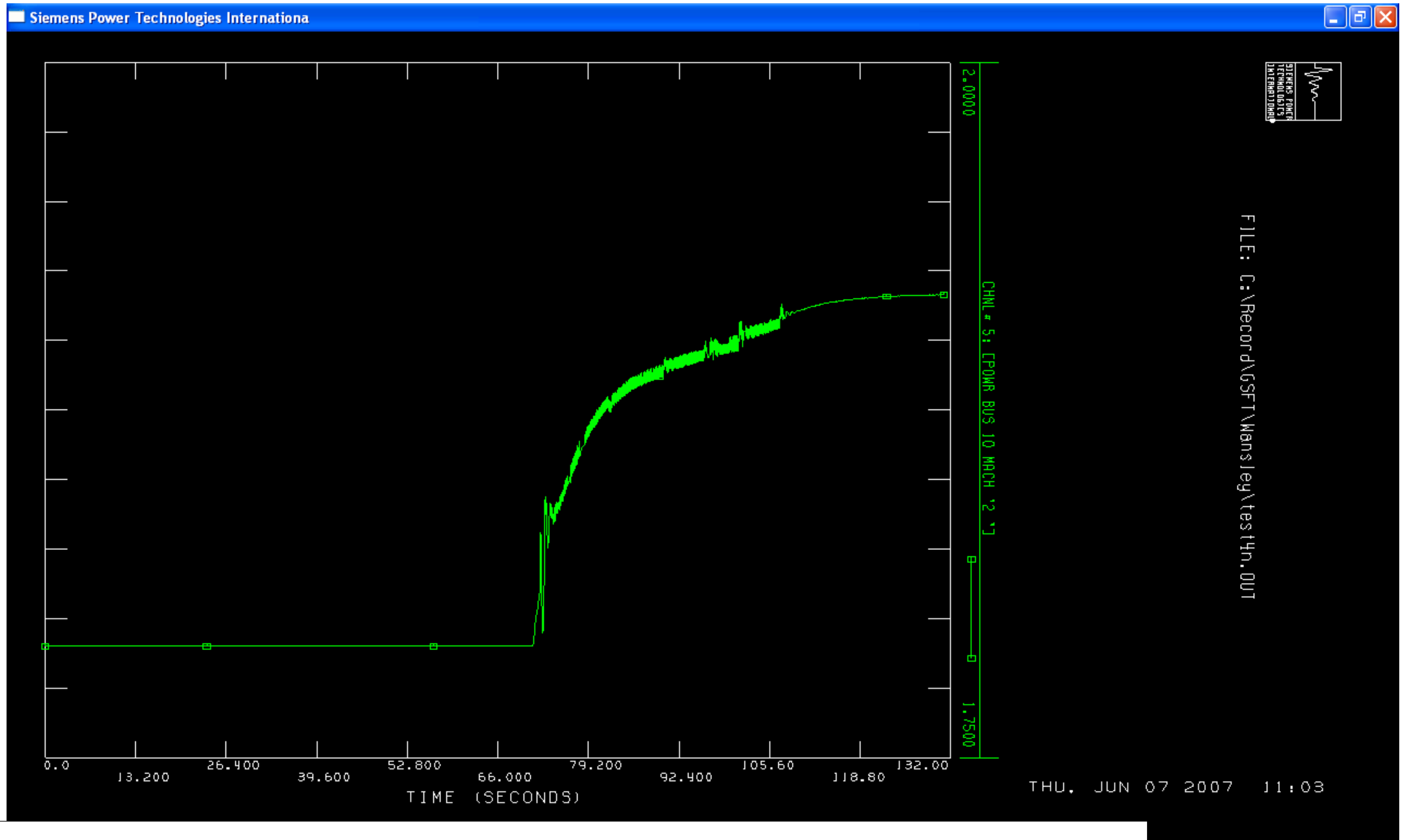
Simulation at White Bluff U2 (Coal fired)

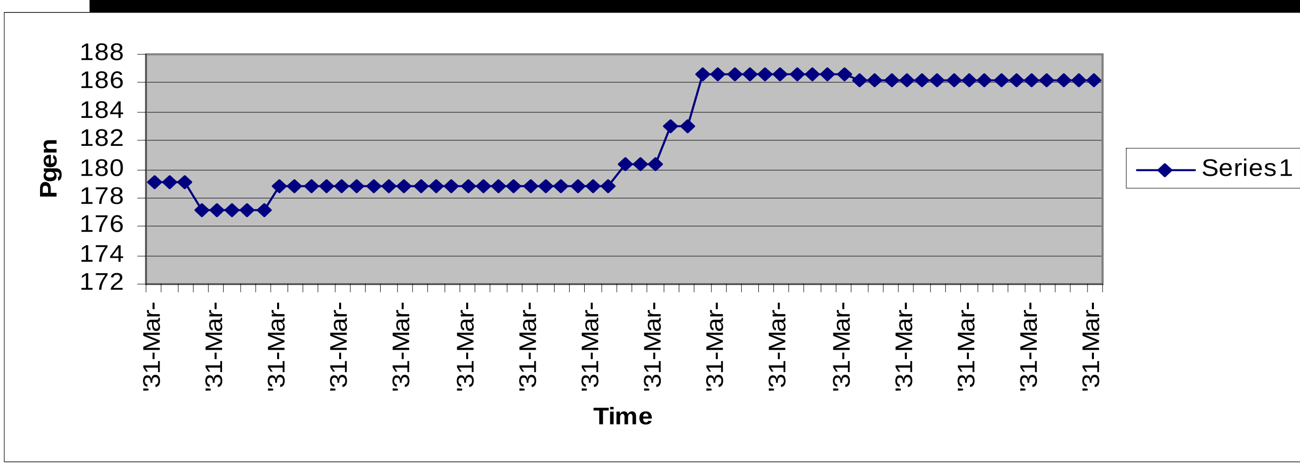

Siemens Power Technologies Internationa
8.5000
8.0000
CHNL # 5: [POWR BUS 10 MACH '2 ']
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
FILE: C:\Record\GSFT\Wansley\test4w.OUT
THU, JUN 07 2007 11:02


Pgen
840
838
836
834
832
830
828
826
824
822
820
'31-Mar-
Time
Series1

Wansley Event

Simulation at Nelson U4 (Gas fired)


Siemens Power Technologies Internationa
2.0000
1.7500
CHNL # 5: [POWR BUS 10 MACH '2 ']
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
FILE: C:\Record\GSFT\Wansley\test4n.OUT
THU, JUN 07 2007 11:03


Pgen
188
186
184
182
180
178
176
174
172
'31-Mar-
Time
Series1

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) NOT SURE
   - If yes, what is the maintenance interval? (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) NOT SURE
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) We were not able to perform this test. Our EMS currently does not log individual Unit MWs at 6 seconds or less intervals. I was able to get MWs for some units from unit controllers, but unit control system clocks were not synchronized with the EMS clock. Our TO was also tied up gathering material for the NERC compliance filing.

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? (hours)
   - How long did it take to set up the model to simulate this event? (hours)
   - How long did it take to compare the generator output data to the model? (hours)
   - Did the model parameters or type need to be changed?

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study.
5. Please list any suggested changes to the guideline?
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Pat Longshore Phone Number: 803-217-7490 Company Name: SCE&G

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name:** __GREENE COUNTY UNIT 1___________
2. **Company:** _ALABAMA POWER COMPANY_________
3. **Date:** _____JUNE 5th, 2007_________________________
4. **Submitter:** _ROSS CAMPBELL______________________
5. **Phone No.** _205-992-7174 (8-992-7174)________________

Governor Information:
Identify general type of governor control:
Mechanical hydraulic (MHC)
Analog electro-hydraulic (EHC)
X Digital electro-hydraulic (DEH)
____

Check type of governor model submitted:
X PTI Standard Model with As built parameters
PTI Standard Model with Estimated Parameters
PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ______5______

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) Under Development
   - If yes, what is the maintenance interval? 36-60 (months) (Depending on Unit Maintenance requirements)

2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) Yes

3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No)

3. A. **If yes:** (Use additional pages if needed to explain.)

- How long did it take to obtain the generator output data? (hours)
- How long did it take to set up the model to simulate this event? (hours)
- How long did it take to compare the generator output data to the model? (hours)
- Did the model parameters or type need to be changed?

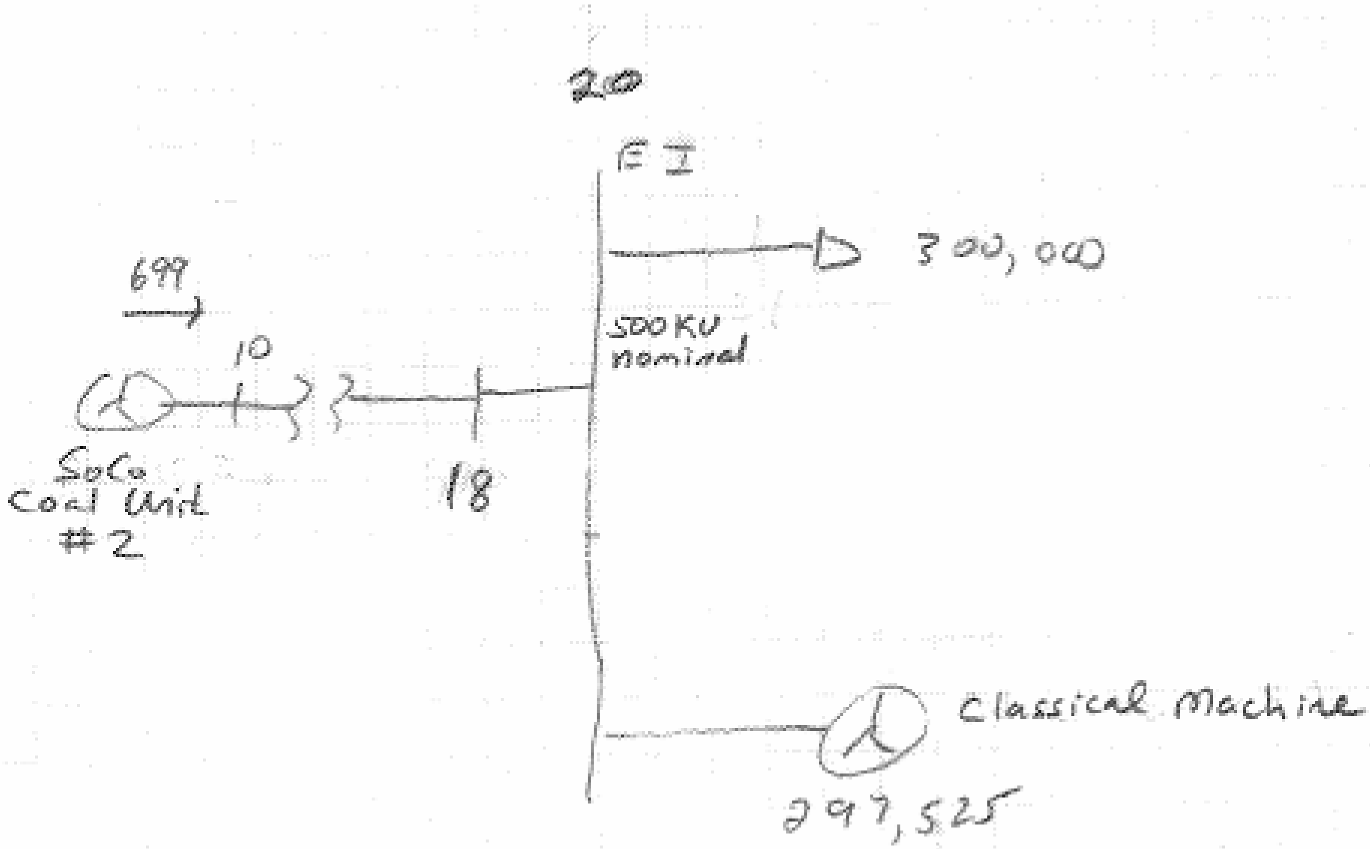
3. B. **If No:**

- Use additional pages to explain.

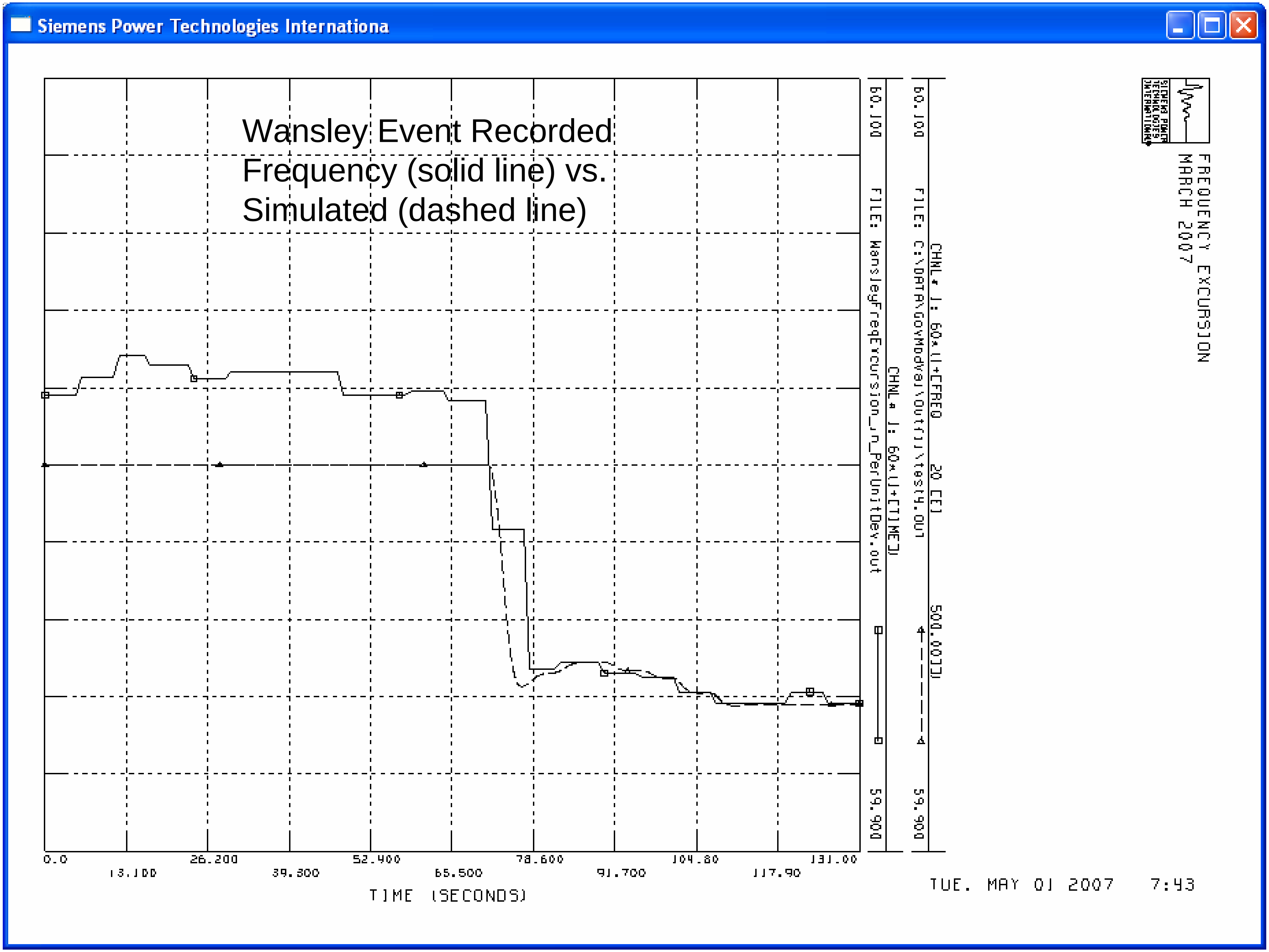
4. List any material costs associated with this study.
5. Please list any suggested changes to the guideline?
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).

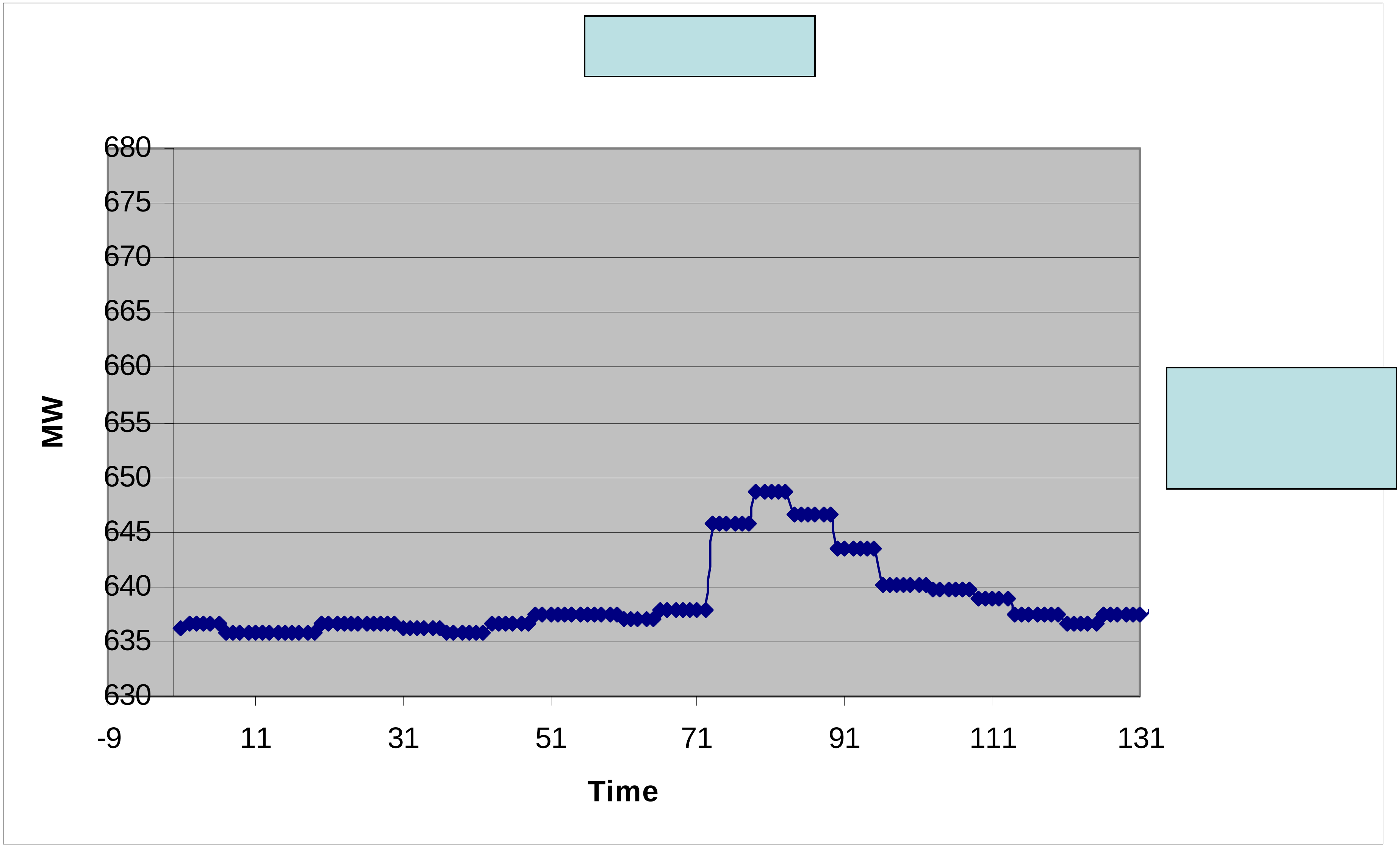
7. Name of the person completing the form: Ross Campbell Phone Number: 205-992-7174 Company Name: Southern Company Services

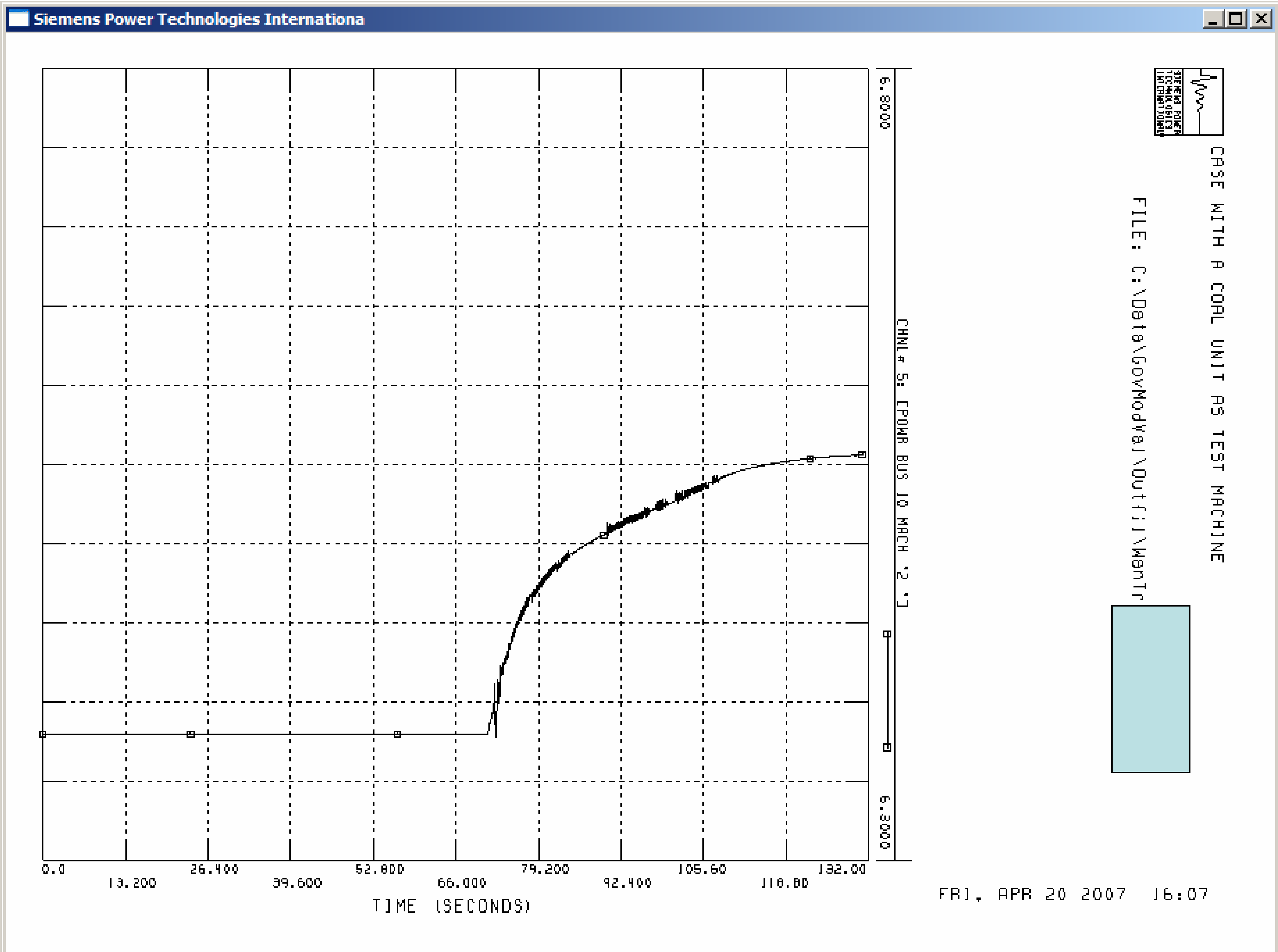
Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.



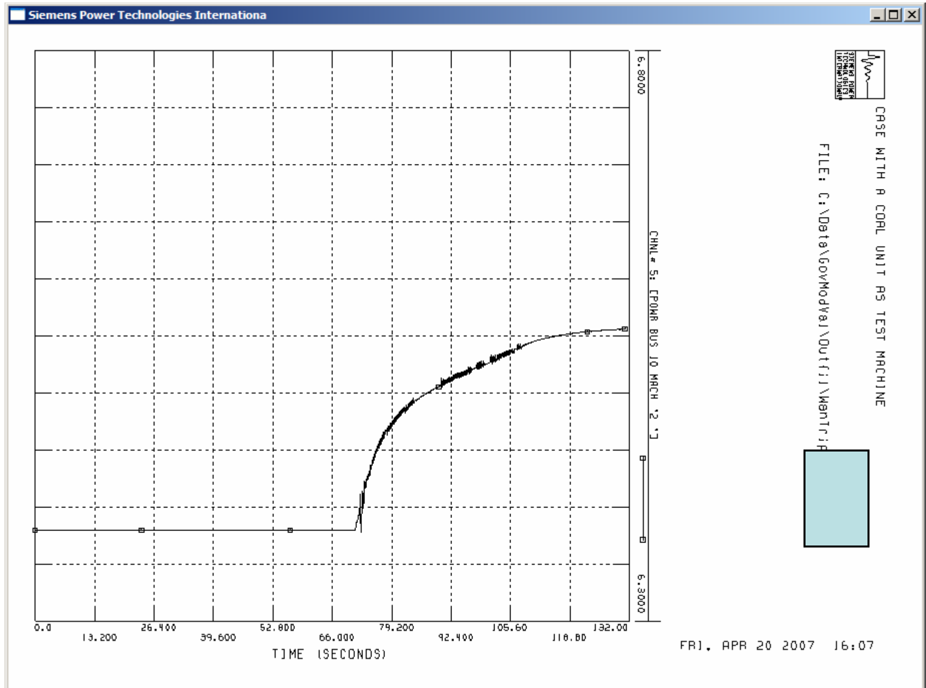
20
EI
300,000
699
10
500KV
nominal
SoCo
Coal Unit
#2
18
Classical Machine
297,525

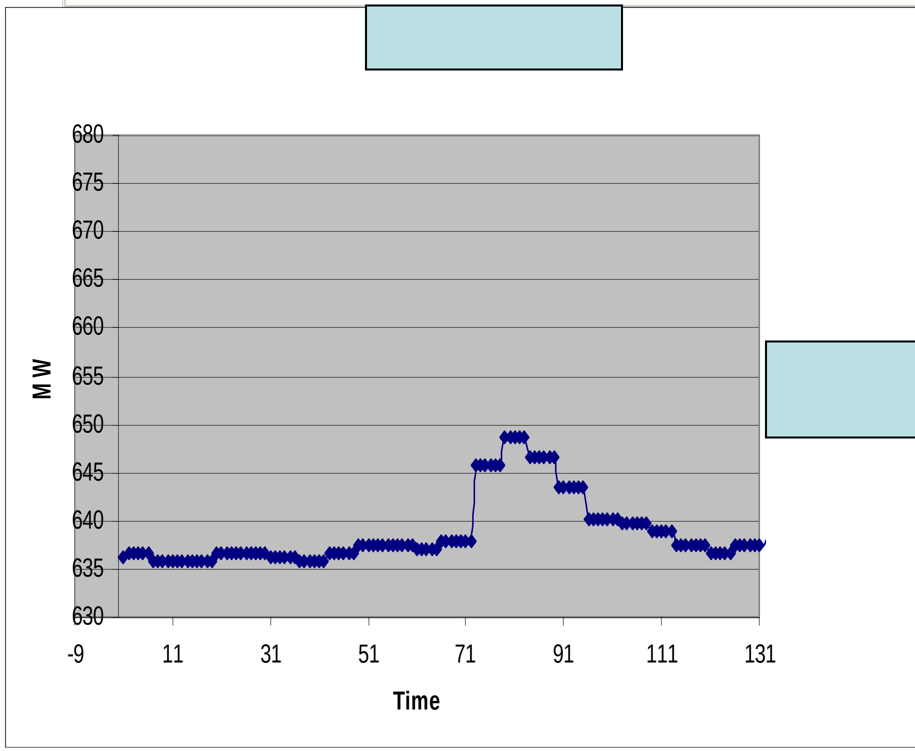

Siemens Power Technologies Internationa
Wansley Event Recorded
Frequency (solid line) vs.
Simulated (dashed line)
0.0
13.100
26.200
39.300
52.400
65.500
78.600
91.700
104.80
117.90
131.00
TIME (SECONDS)
60.100
FILE: WansleyFreqExcursion_in_PerUnitDev.out
CHNL# 1: 60*(1+[TIME])
59.900
FILE: C:\DATA\GovModVal\Out\test4.out
CHNL# 1: 60*(1+[FREQ 20 [E] 500.00]]
FREQUENCY EXCURSION
MARCH 2007
TUE, MAY 01 2007 7:43

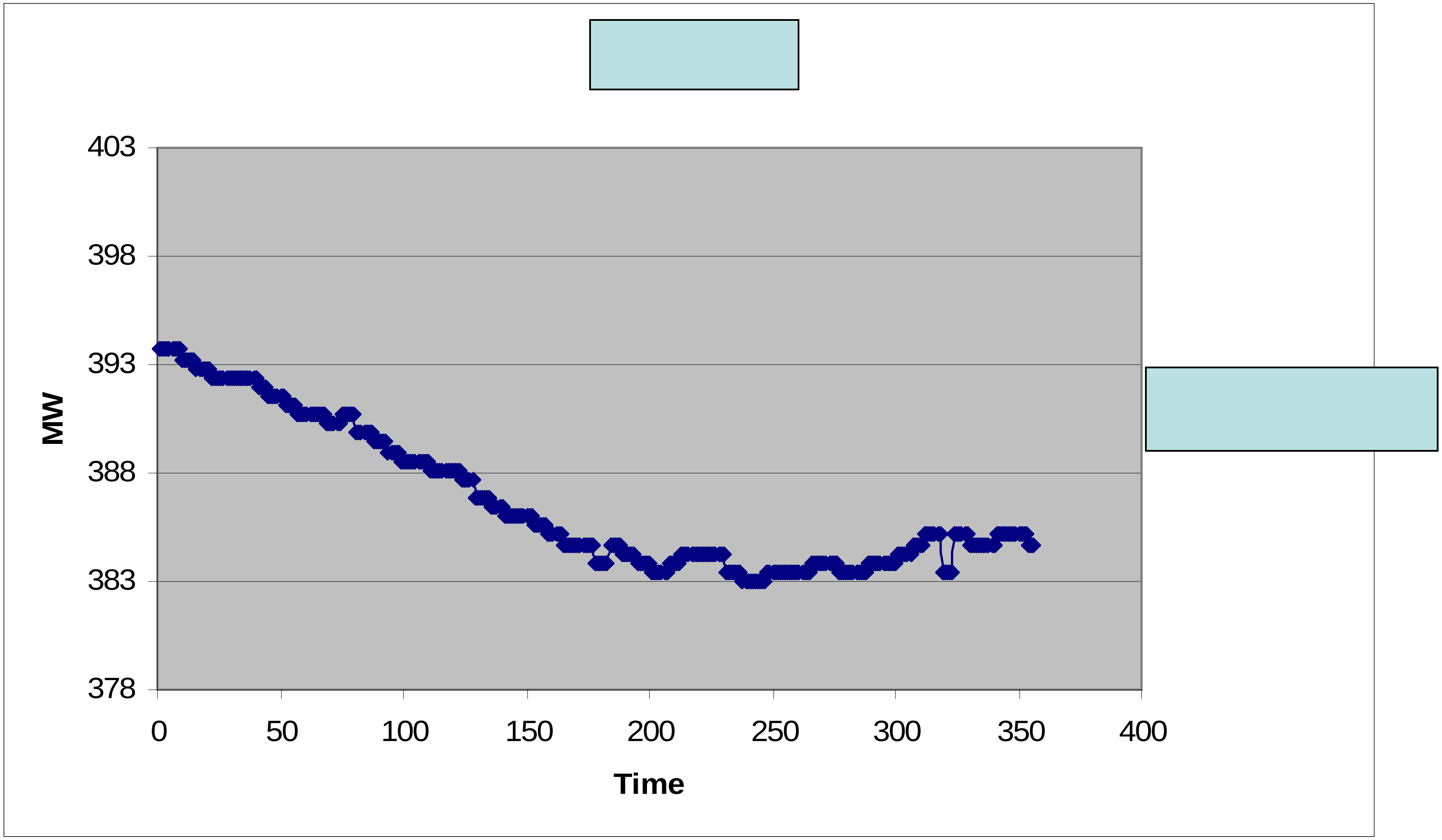

680
675
670
665
660
655
650
645
640
635
630
MW
-9
11
31
51
71
91
111
131
Time

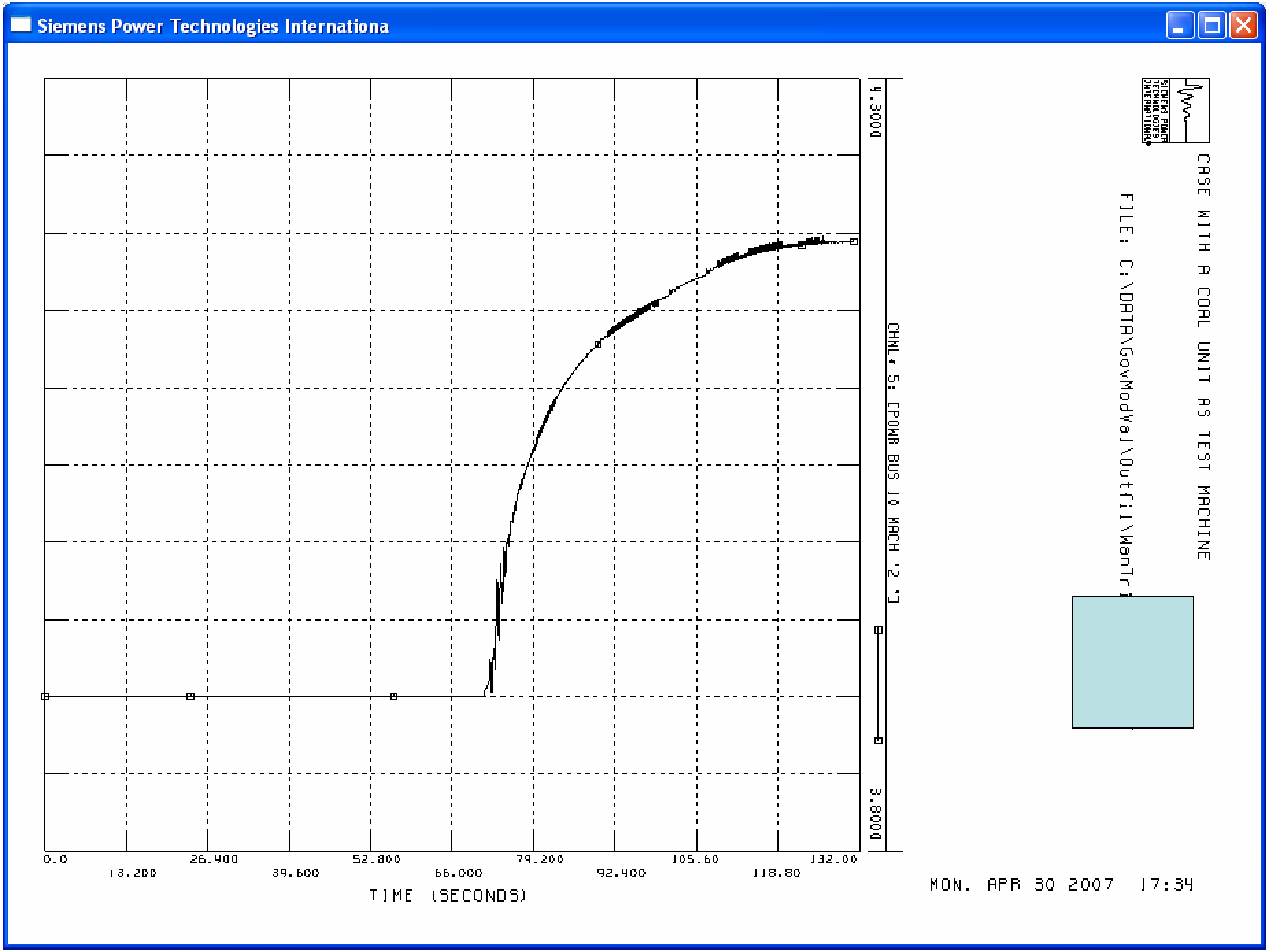


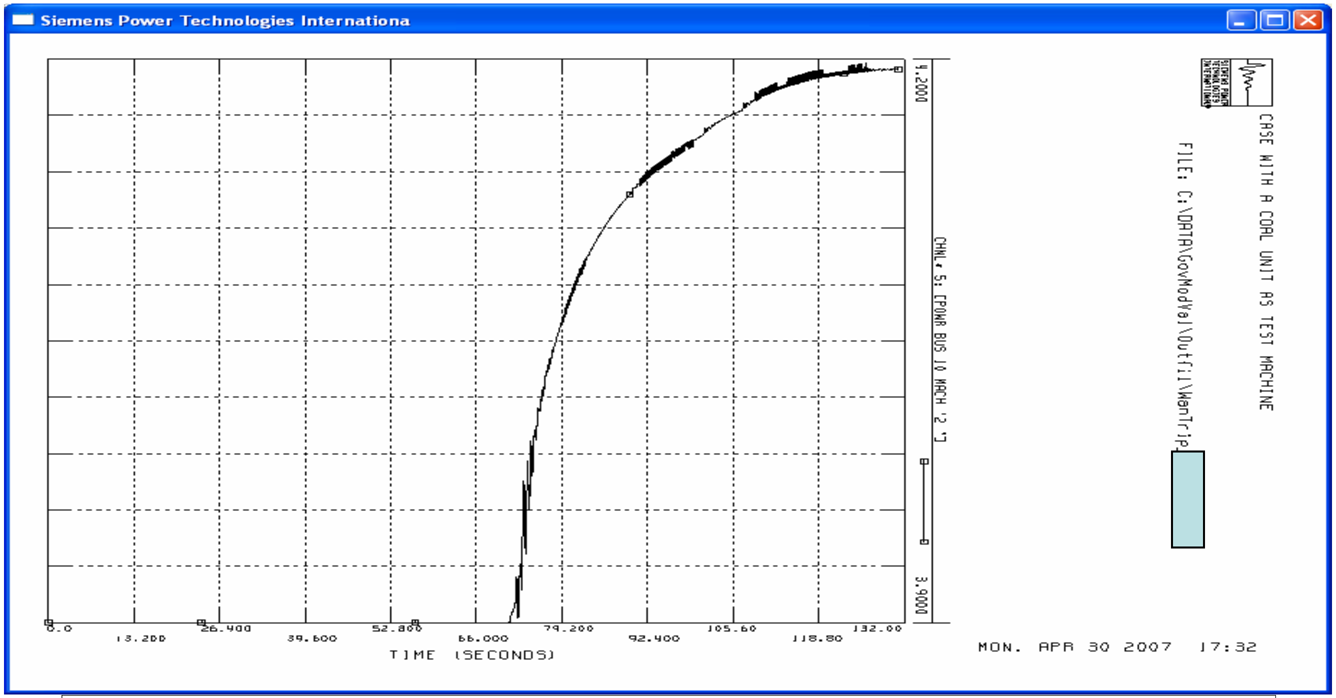
Siemens Power Technologies Internationa
6.8000
6.3000
CHNL# 5: [POWR BUS 10 MACH '2 ']
CASE WITH A COAL UNIT AS TEST MACHINE
FILE: C:\Data\GovModVal\Outfil\Wantr
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
FRI, APR 20 2007 16:07


Siemens Power Technologies Internationa
6.8000
6.3000
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
CASE WITH A COAL UNIT AS TEST MACHINE
FRI, APR 20 2007 16:07

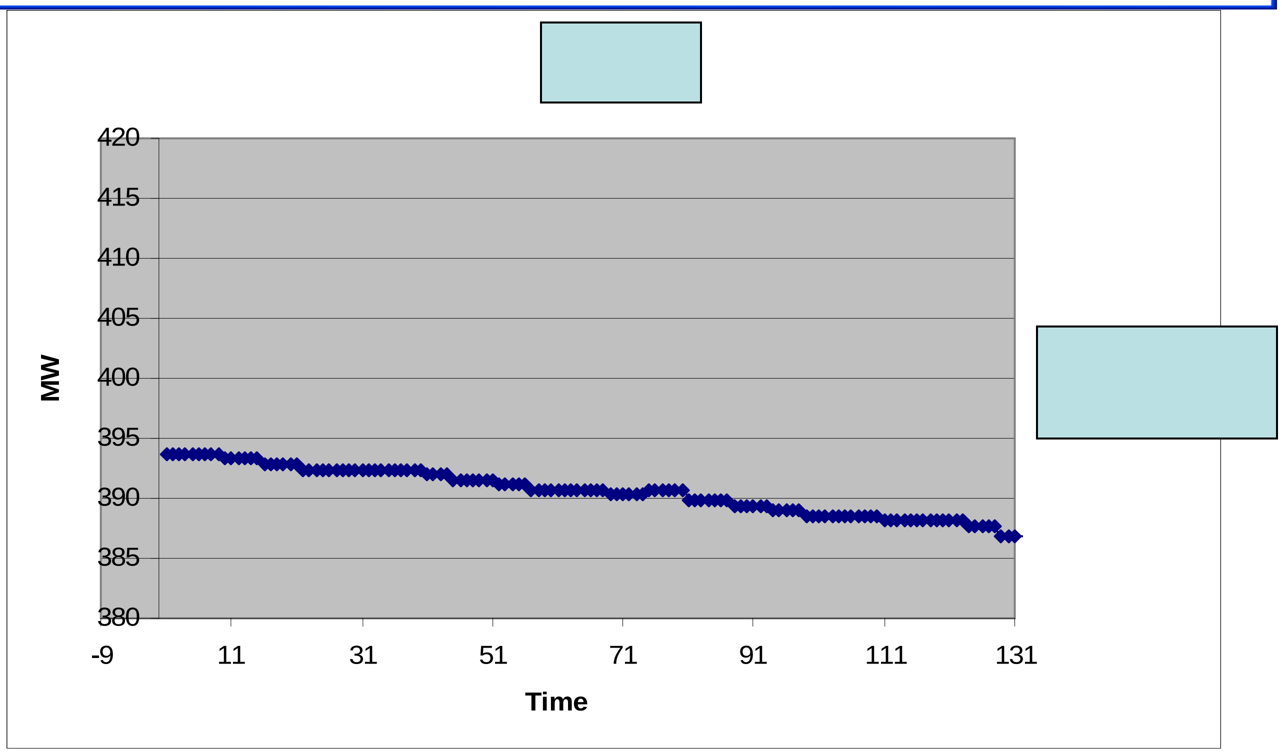

680
675
670
665
660
655
650
645
640
635
630
MW
-9
11
31
51
71
91
111
131
Time


MW
403
398
393
388
383
378
0
50
100
150
200
250
300
350
400
Time

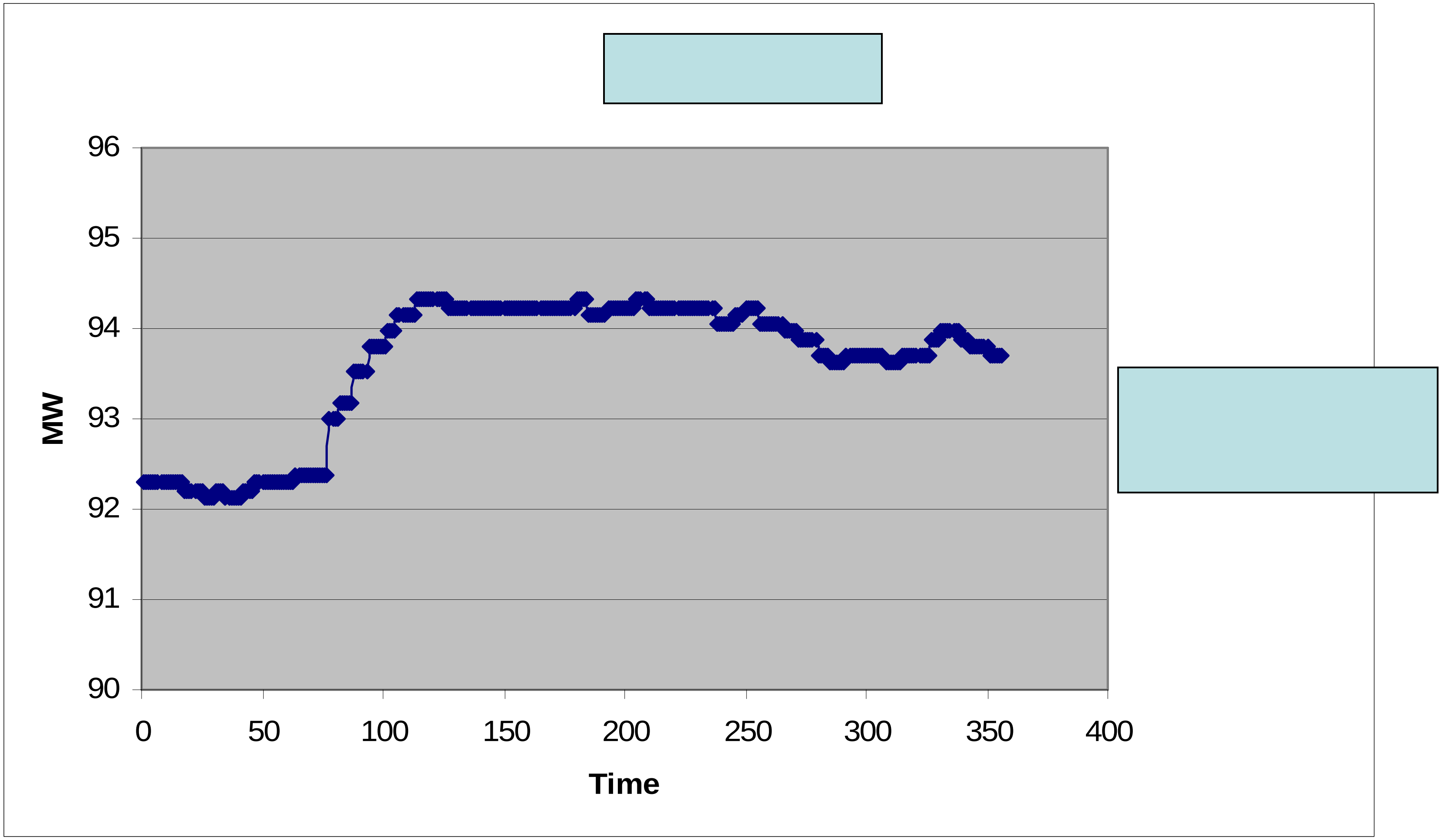

Siemens Power Technologies Internationa
4.3000
3.8000
CHNL# 5: [POWR BUS 10 MACH '2 ']
CASE WITH A COAL UNIT AS TEST MACHINE
FILE: C:\DATA\GovModVal\Outfil\WanTr
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
MON. APR 30 2007 17:34



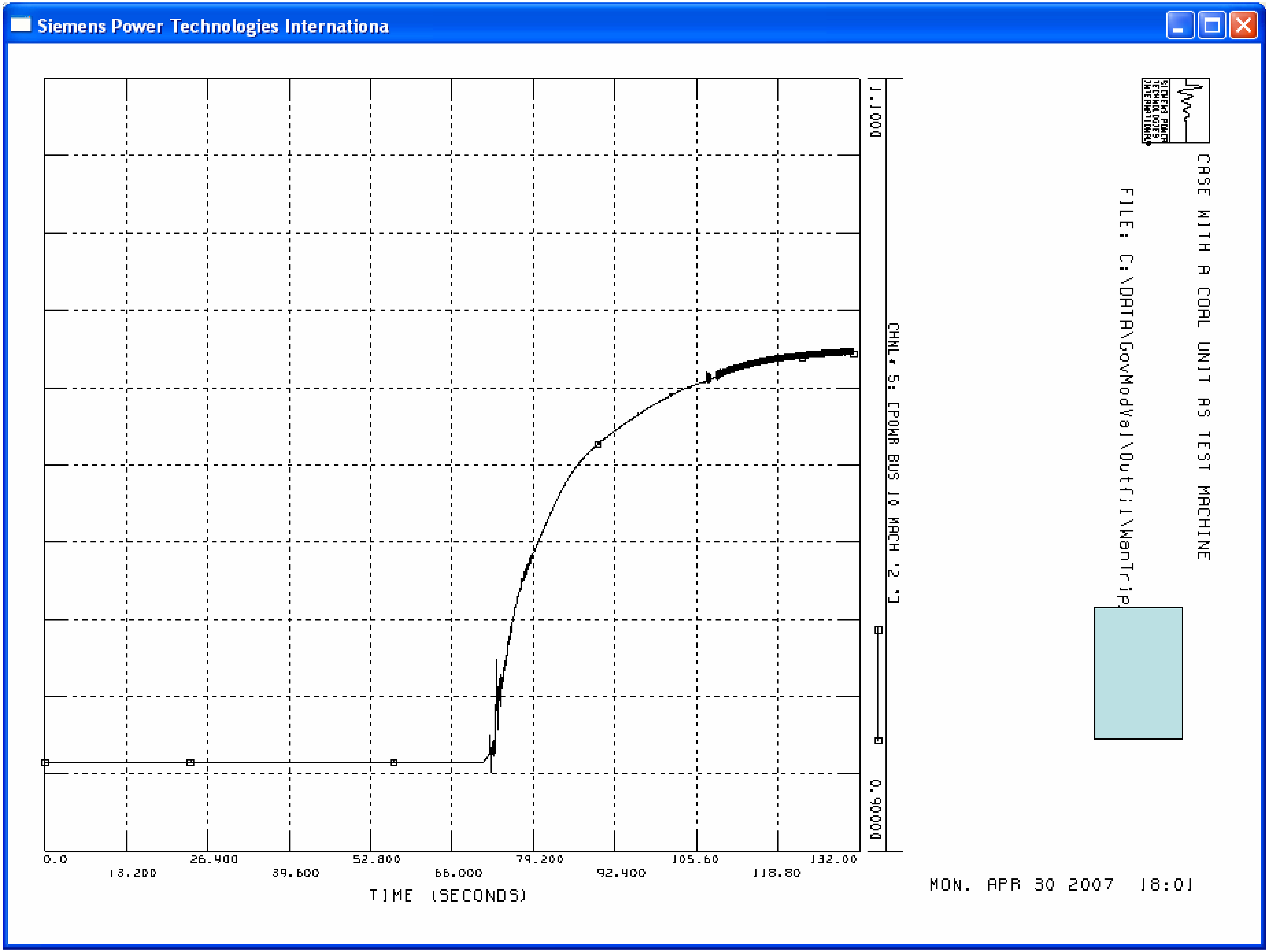
Siemens Power Technologies Internationa
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
4.2000
3.9000
CASE WITH A COAL UNIT AS TEST MACHINE
MON. APR 30 2007 17:32

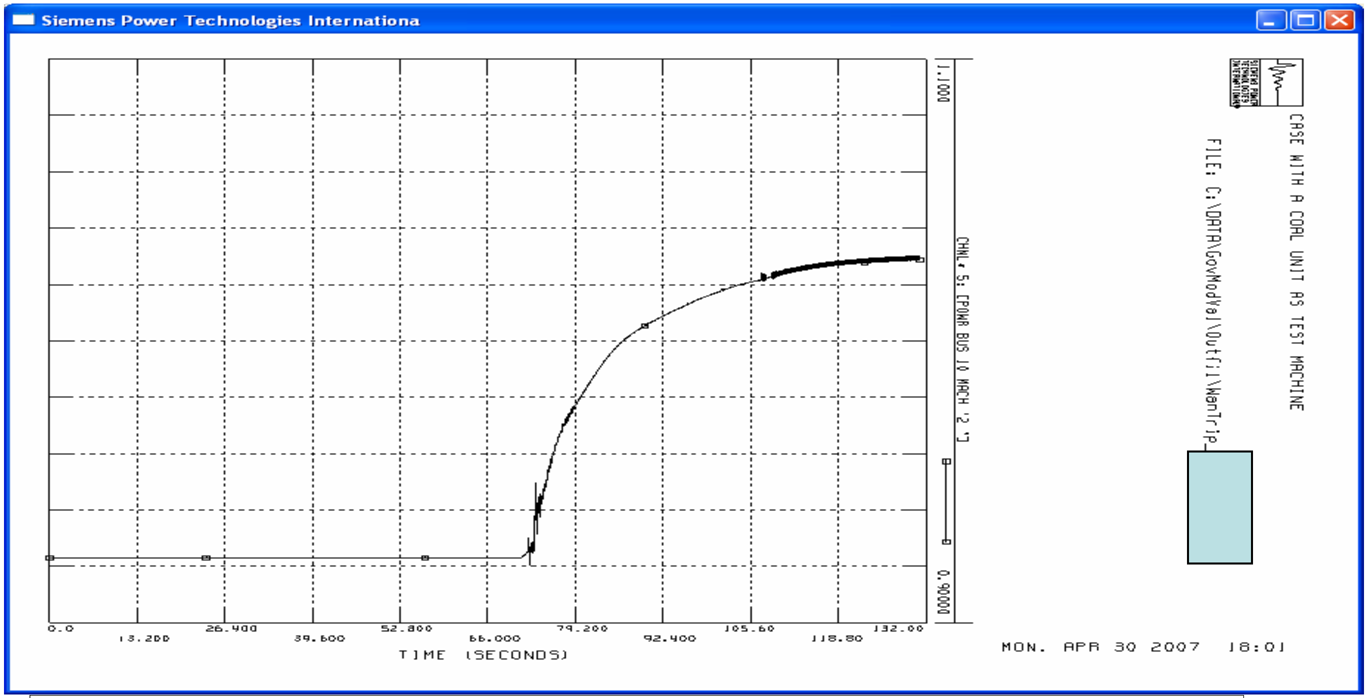


420
415
410
405
400
395
390
385
380
MW
-9
11
31
51
71
91
111
131
Time

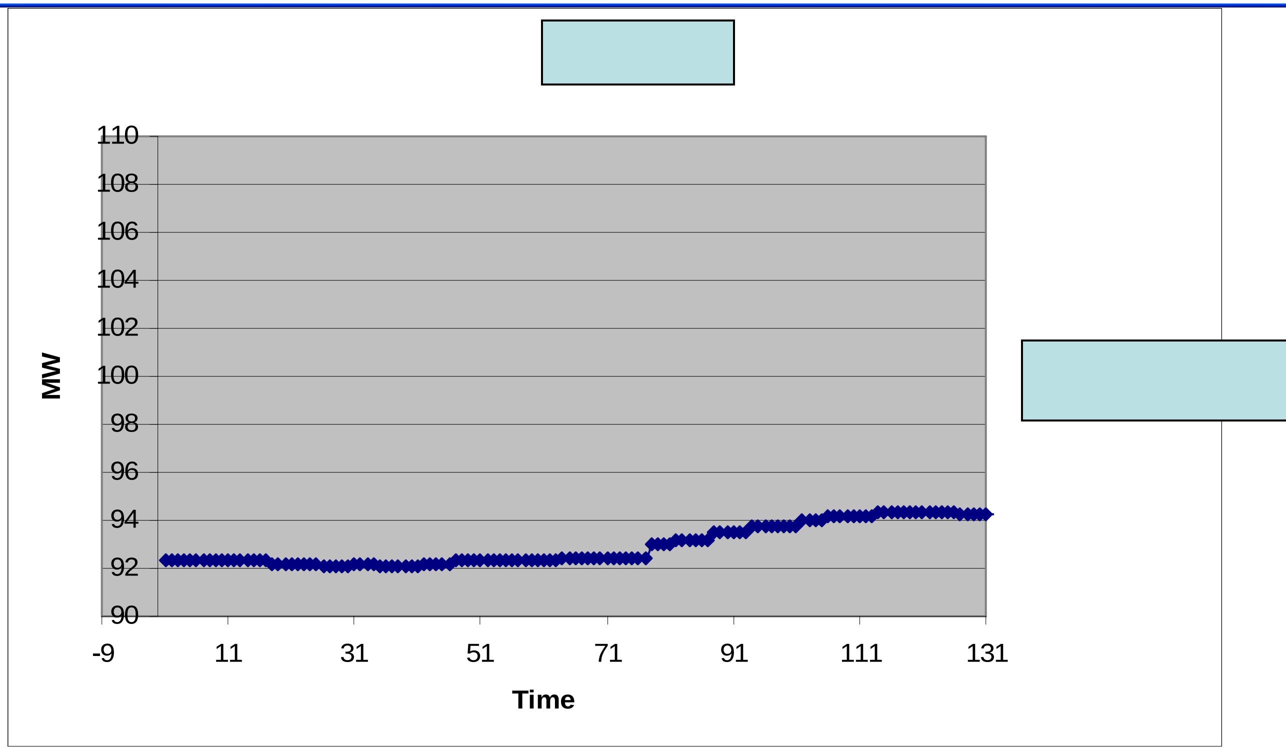


96
95
94
93
92
91
90
MW
0
50
100
150
200
250
300
350
400
Time


Siemens Power Technologies Internationa
1.1000
0.90000
CHNL# 5: [POWR BUS 10 MACH '2 ']
CASE WITH A COAL UNIT AS TEST MACHINE
FILE: C:\DATA\GovModVal\Outfil\WanTrip
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
MON, APR 30 2007 18:01

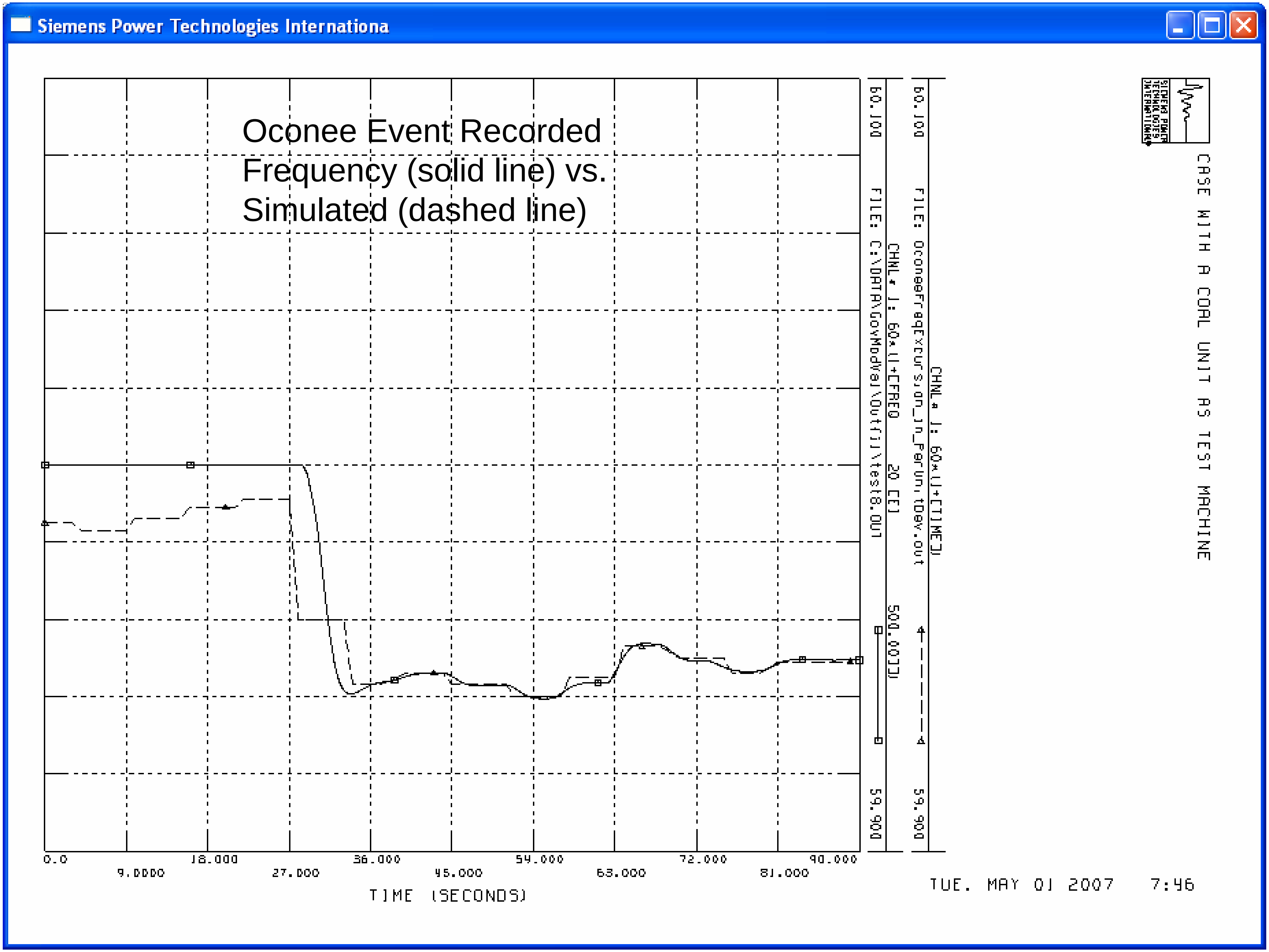


Siemens Power Technologies Internationa
1.1000
0.90000
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
CHNL# 5: [POWR BUS 10 MACH '2 ']
CASE WITH A COAL UNIT AS TEST MACHINE
FILE: C:\DATA\GovModVal\Outfil\WanTrip
MON. APR 30 2007 18:01

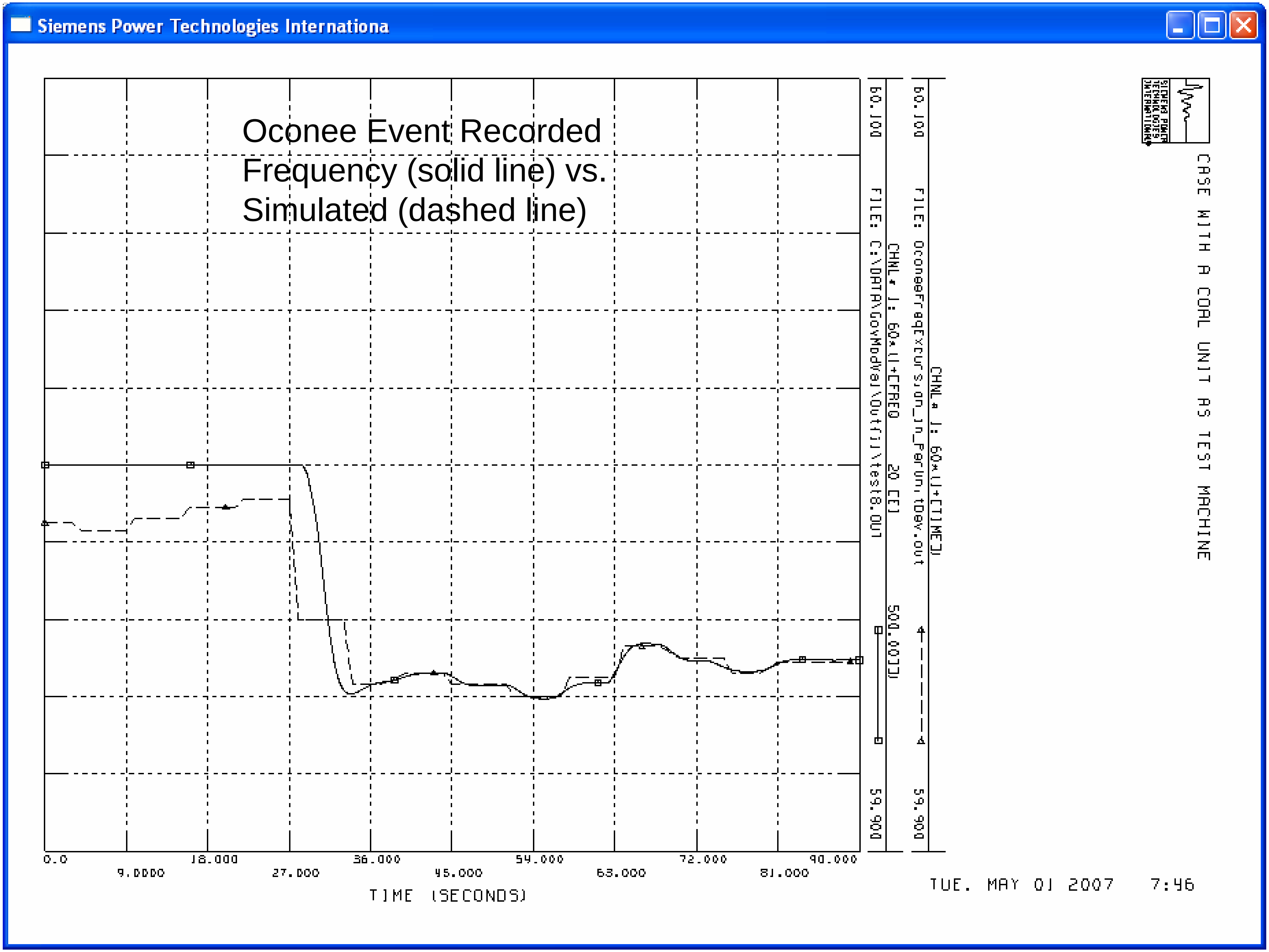


110
108
106
104
102
100
98
96
94
92
90
MW
-9
11
31
51
71
91
111
131
Time

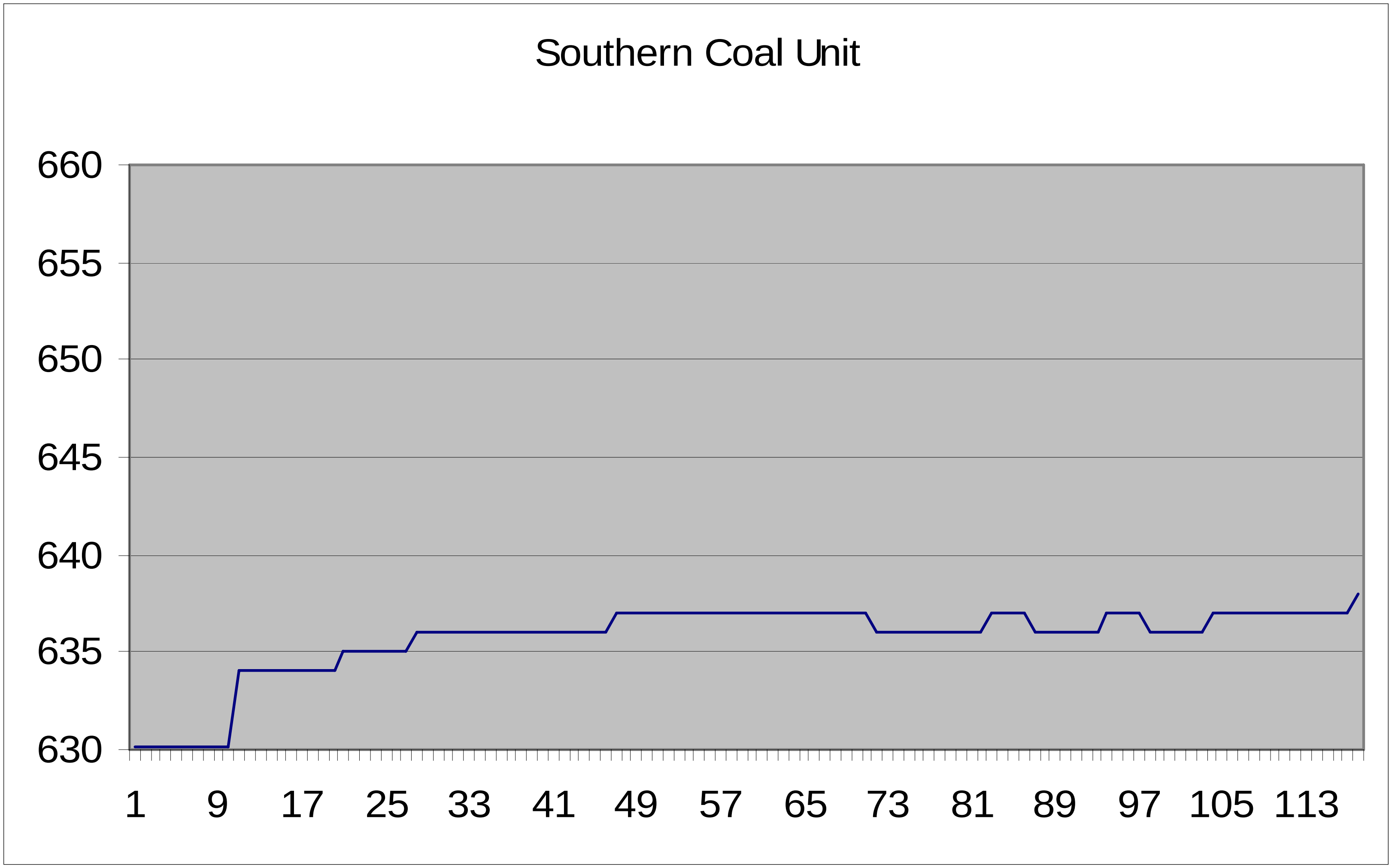
Oconee Trip Responses

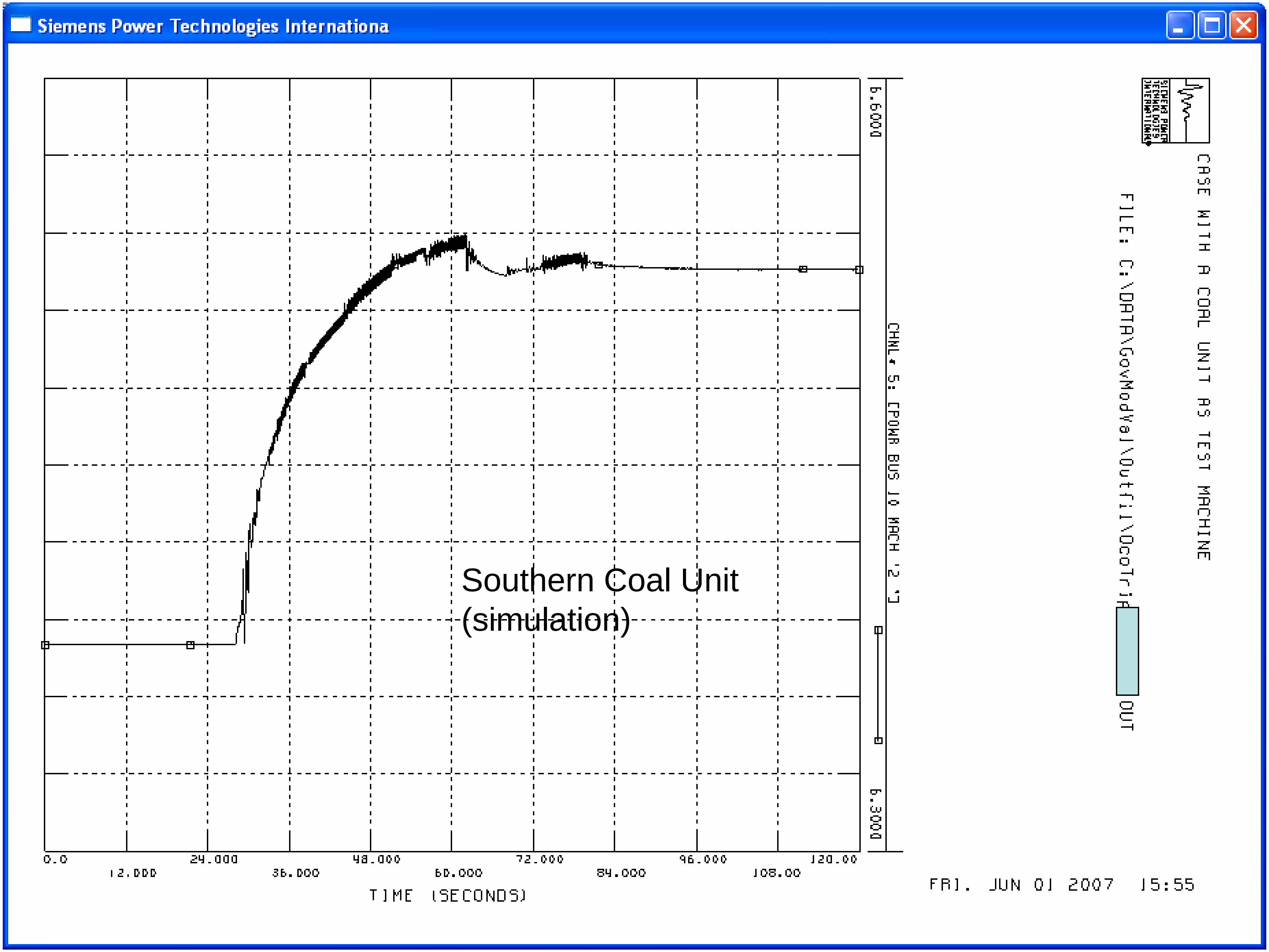

Siemens Power Technologies Internationa
Oconee Event Recorded Frequency (solid line) vs. Simulated (dashed line)
60.100
FILE: C:\DATA\GovModVal\Outfil\test8.OUT
CHNL# 1: 60*(1+CFREQ 20 [E]
59.900
60.100
FILE: OconeeFreqExcursion_in_Perunit.Dev.out
CHNL# 1: 60*(1+[TIME])
59.900
CASE WITH A COAL UNIT AS TEST MACHINE
0.0
9.0000
18.000
27.000
36.000
45.000
54.000
63.000
72.000
81.000
90.000
TIME (SECONDS)
TUE. MAY 01 2007 7:46

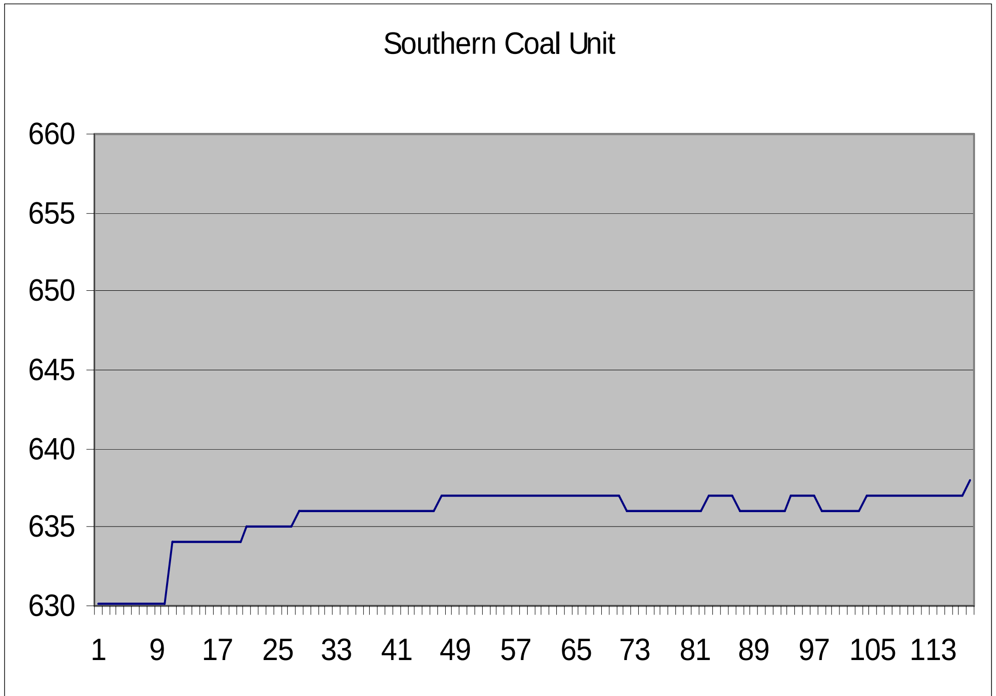
Oconee Event Recorded Frequency (solid line) vs. Simulated (dashed line)



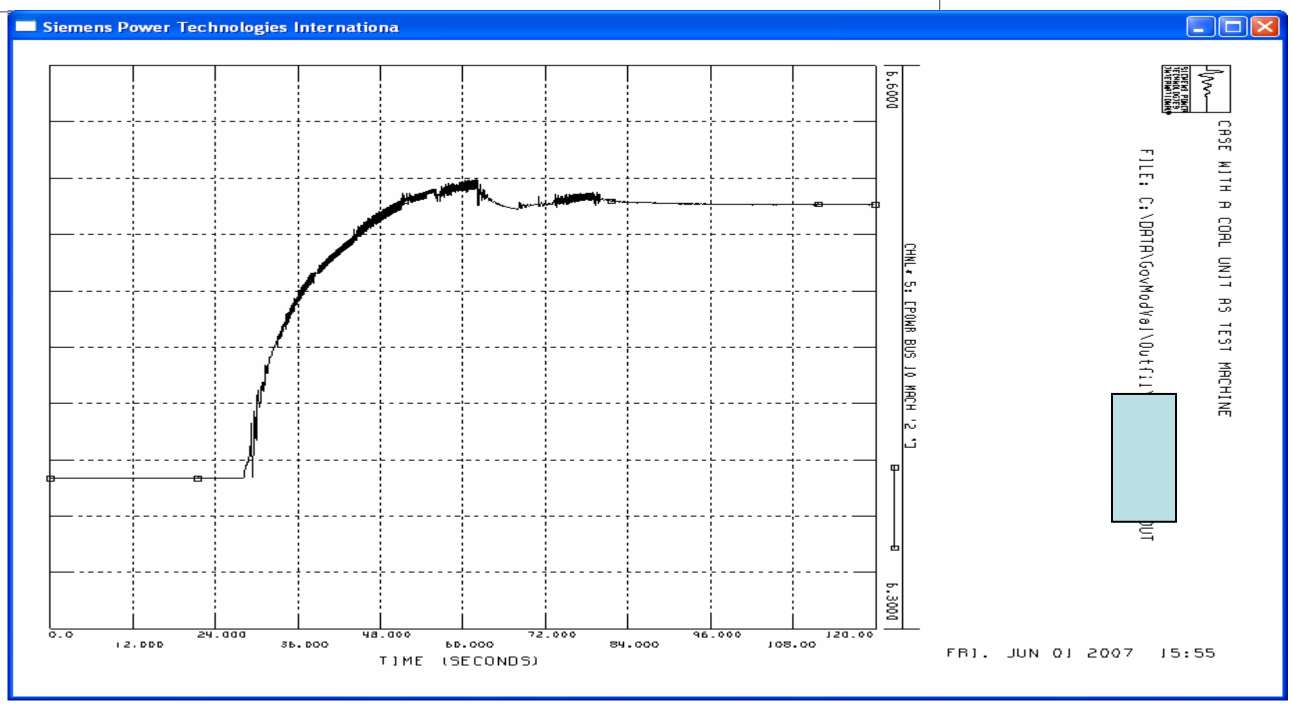
Southern Coal Unit (event data)

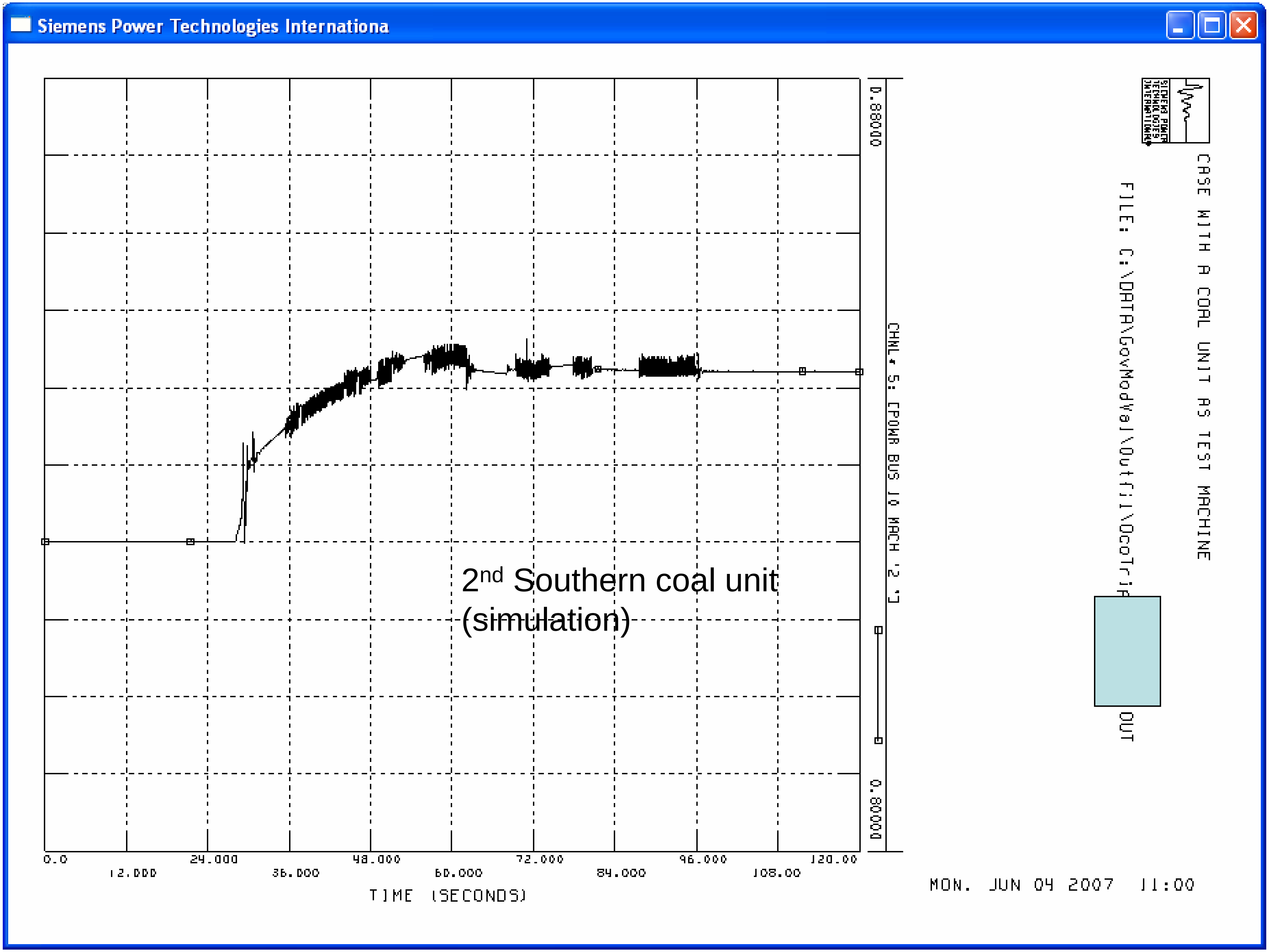



Siemens Power Technologies Internationa
Southern Coal Unit
(simulation)
6.6000
6.3000
CHNL # 5: [POWR BUS 10 MACH '2 ']
CASE WITH A COAL UNIT AS TEST MACHINE
OUT
0.0
12.000
24.000
36.000
48.000
60.000
72.000
84.000
96.000
108.00
120.00
TIME (SECONDS)
FRI, JUN 01 2007 15:55



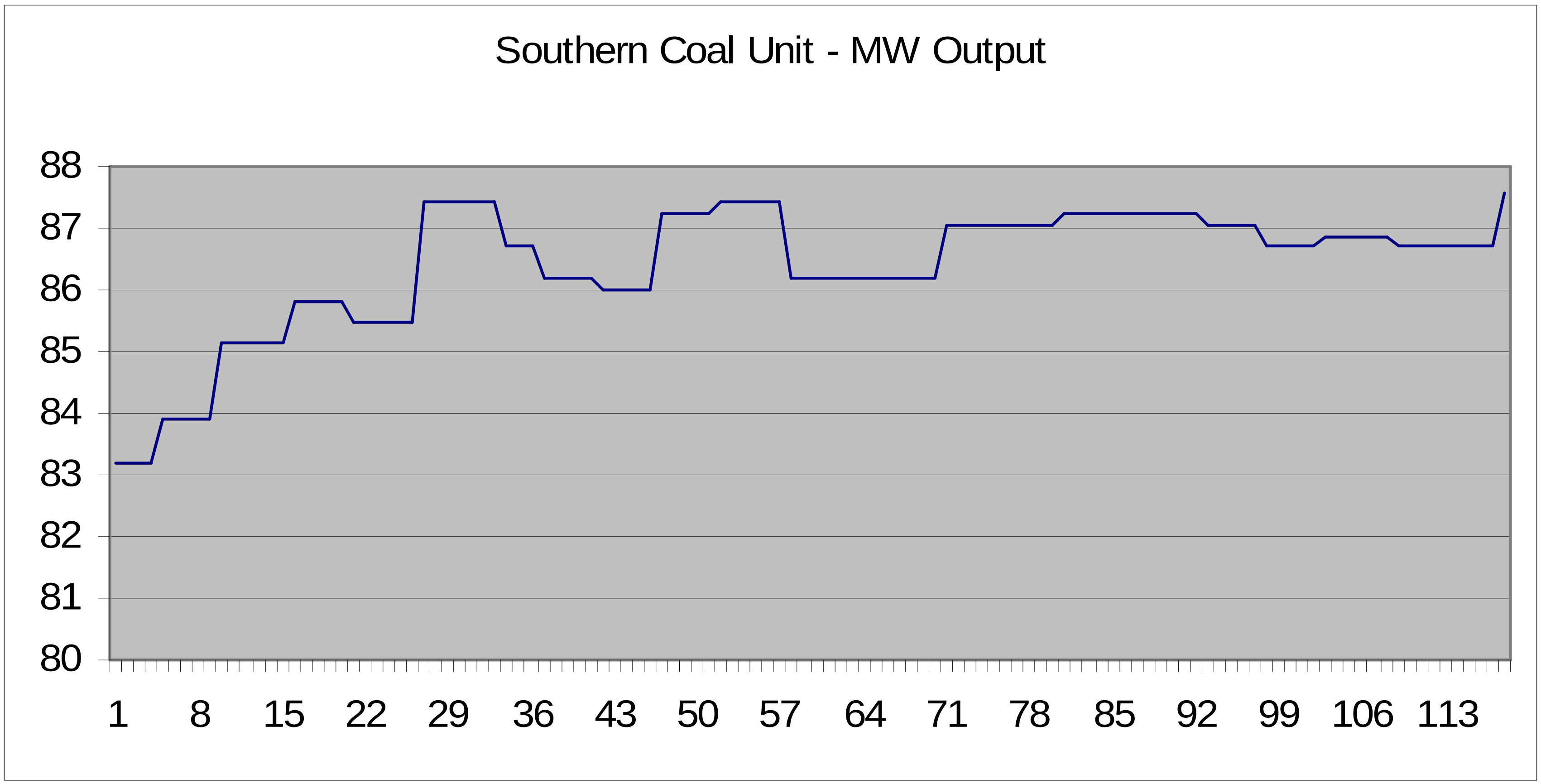
Observations – unit had just ramped up about 5 MW before the event – after the event, it did not respond. Expected response for a 5% droop – approximately 14 MW

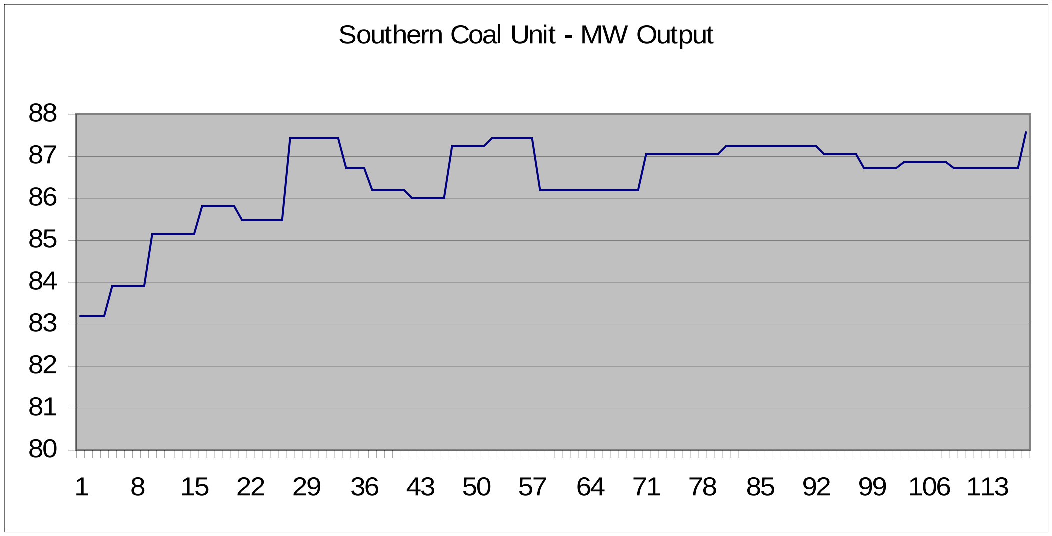




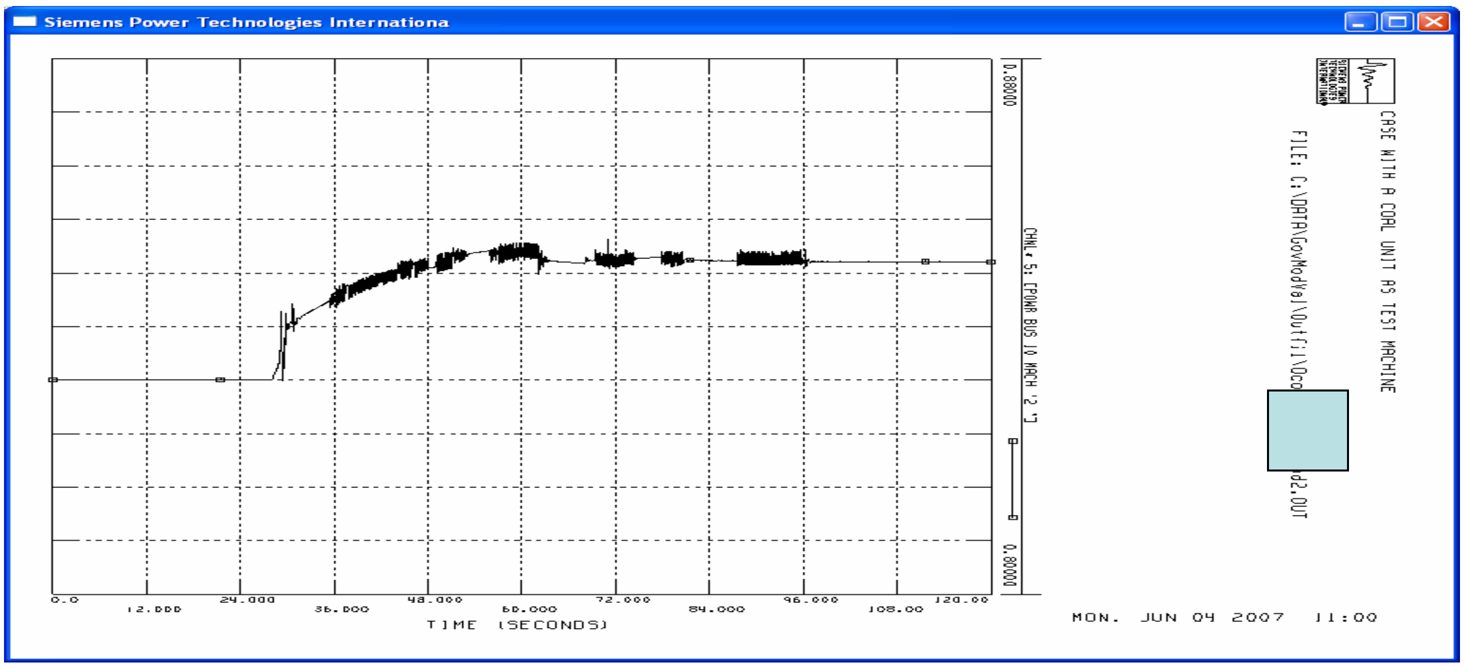
2nd Southern coal unit (simulation)

2nd Southern Coal Unit (event data)





Observations – event data shows that the unit increased approximately 3.5 MW – actually surpassing the approximate expected 2.5 MW increase for a 5% droop. Model predicted a 3 MW increase



Attachment 5
PRC-019 Test Results

- **SERC PRC-019 Field Test Reporting Form - COE 6-8-2007.pdf**
- **Generator Volts per Hertz.pdf**
- **09. PRC-019 Field Test Reporting Form Dominion.doc**
- **Generator Capability Curve.pdf**
- **Entergy SERC PRC-019 Field Test Reporting Form Rev 1 _11-2-06_.pdf**
- **Entergy PRC019 Field Test.pdf**
- **serc prc-019 field test reporting form rev 1 (11-2-06)(Completed).doc**
- **PRC-019 Curves.xls**
- **SCG PRC-019 Field Test Reporting Forms.pdf**
- **SCG PRC-019 Sample Generator Coordination Plots.pdf**

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

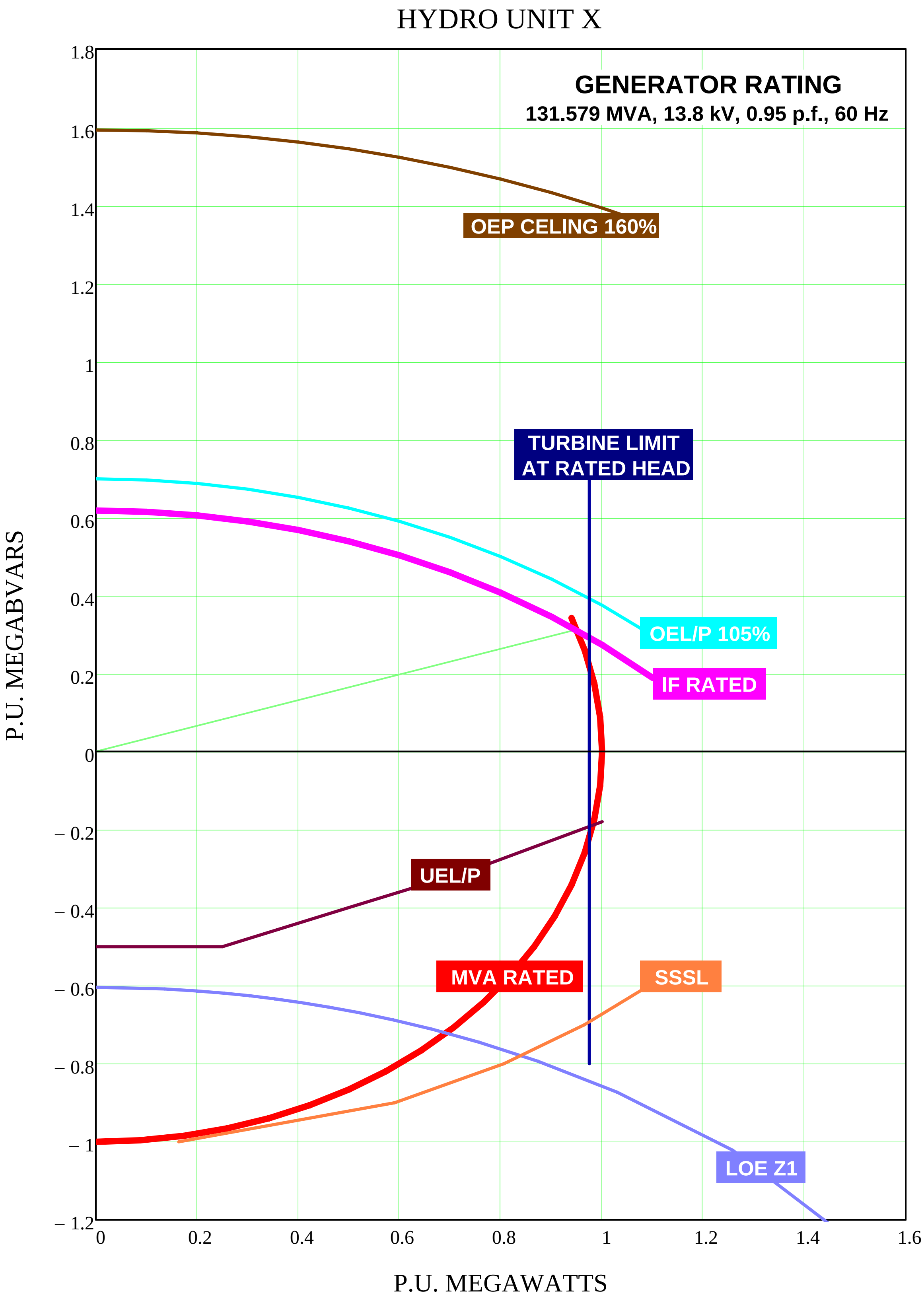
1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? ___40_____ Hours
2. What methodology / tools were used to perform the coordination studies?

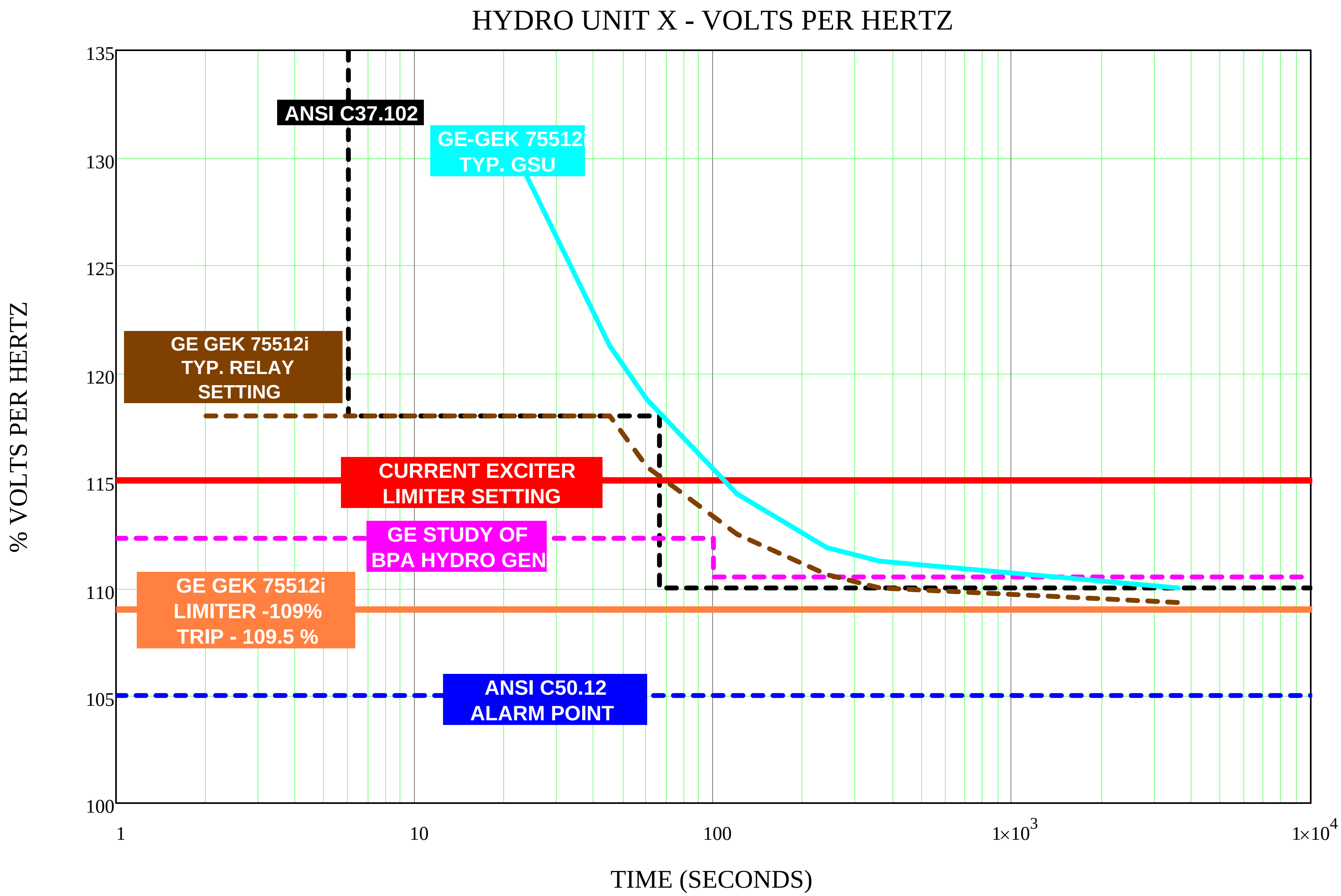
   ☐ Computerized coordination curves

   ☐ Manual coordination curves

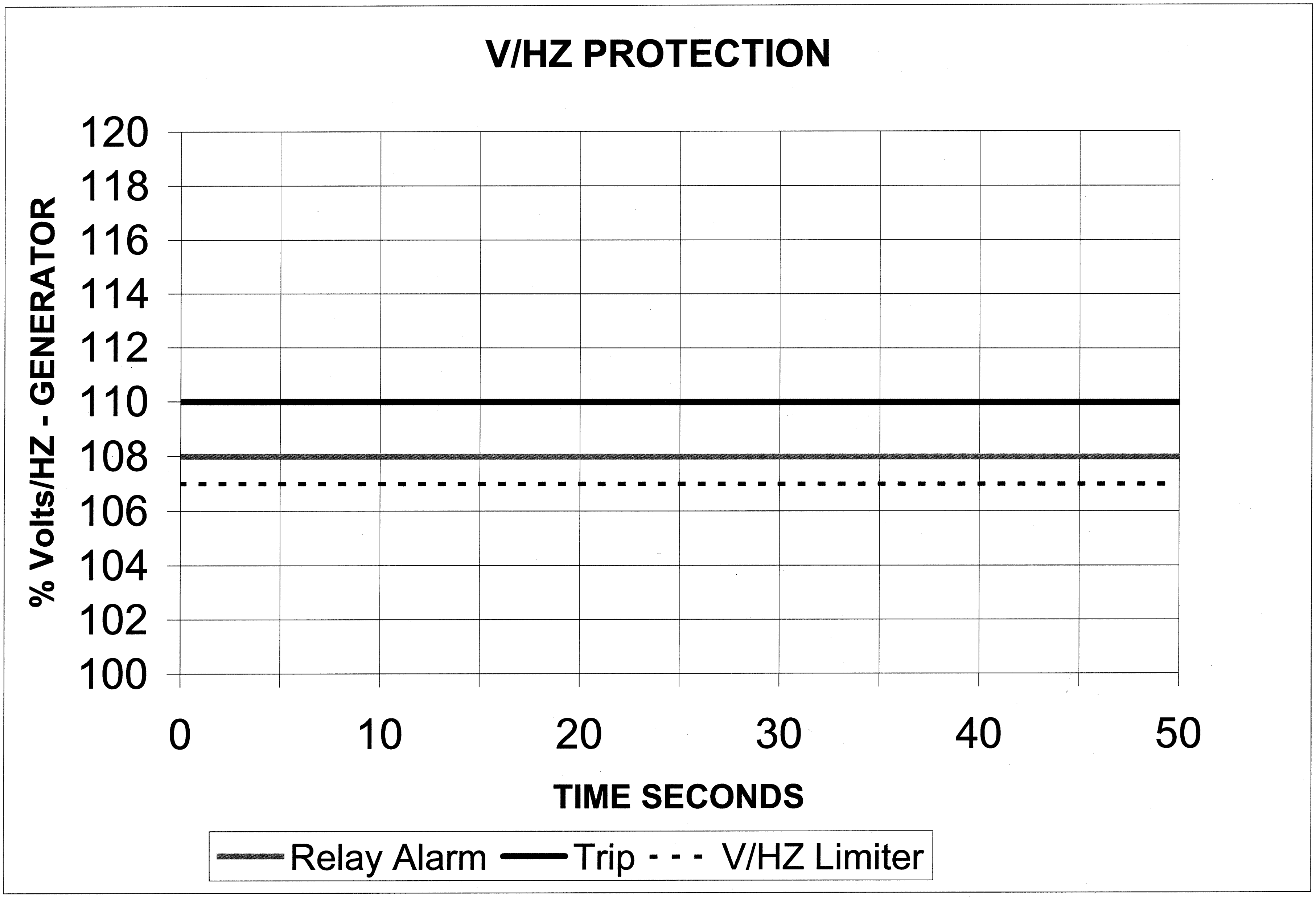
   ☒ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? ___320______
4. How long did it take to analyze the technical information and draw the curves (plots)? __40______ Hours
5. List any material costs associated with this study. ____Curve plotting Software $1,810.____
   ____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? __Yes______ (Yes or No)
7. If not, list the devices that needed configuration changes: ___The settings were coordinated with the capability curve; however the Volts/Hz limit and trip were set to high.
   ____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
   ____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc). Attached.
10. Name of person completing form: _David Williams__ Phone number _706.643.0313__Company name __Corps of Engineers – Mobile District
    ____

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.


HYDRO UNIT X
GENERATOR RATING
131.579 MVA, 13.8 kV, 0.95 p.f., 60 Hz
OEP CELING 160%
TURBINE LIMIT
AT RATED HEAD
OEL/P 105%
IF RATED
UEL/P
MVA RATED
SSSL
LOE Z1
P.U. MEGABVARS
P.U. MEGAWATTS
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
– 0.2
– 0.4
– 0.6
– 0.8
– 1
– 1.2
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6



HYDRO UNIT X - VOLTS PER HERTZ
% VOLTS PER HERTZ
TIME (SECONDS)
135
130
125
120
115
110
105
100
1
10
100
1×10^3
1×10^4
ANSI C37.102
GE-GEK 75512
TYP. GSU
GE GEK 75512i
TYP. RELAY
SETTING
CURRENT EXCITER
LIMITER SETTING
GE STUDY OF
BPA HYDRO GEN
GE GEK 75512i
LIMITER -109%
TRIP - 109.5 %
ANSI C50.12
ALARM POINT


V/HZ PROTECTION
% Volts/HZ - GENERATOR
120
118
116
114
112
110
108
106
104
102
100
0
10
20
30
40
50
TIME SECONDS
Relay Alarm
Trip
V/HZ Limiter

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

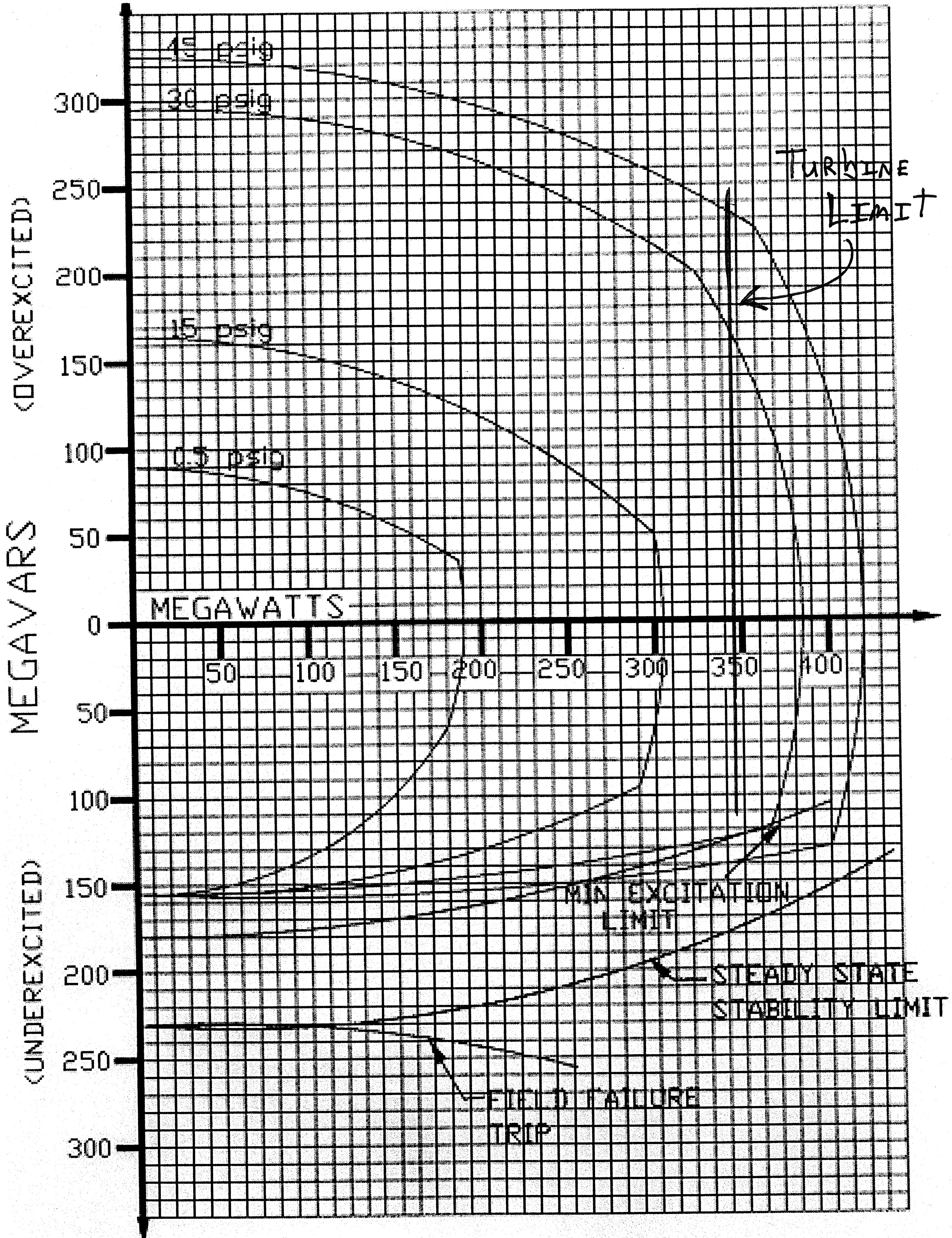
1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? __20__ Hours
2. What methodology / tools were used to perform the coordination studies?

   ☐ Computerized coordination curves

   ☒ Manual coordination curves

   ☐ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? ____10____
4. How long did it take to analyze the technical information and draw the curves (plots)? __20____ Hours
5. List any material costs associated with this study.
   ___________None____
   ____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? _Yes____ (Yes or No)
7. If not, list the devices that needed configuration changes:
   ____
   ____
   ____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
   ______________None____
   ____
   ____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.



45 psig
30 psig
15 psig
0.5 psig
Turbine Limit
MEGAVARS
(OVEREXCITED)
(UNDEREXCITED)
MEGAWATTS
300
250
200
150
100
50
0
50
100
150
200
250
300
350
400
MIN EXCITATION LIMIT
STEADY STATE STABILITY LIMIT
FIELD FAILURE TRIP

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

<u>Provide the following information:</u>

1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? ___80_____ Hours
2. What methodology / tools were used to perform the coordination studies?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☒ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools?
   ____200_____
4. How long did it take to analyze the technical information and draw the curves (plots)? ___30_____ Hours
5. List any material costs associated with this study. __$35k contractor costs ____Regulator calibration and coordination study. __________________
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? ___Yes_____ (Yes or No)
7. If not, list the devices that needed configuration changes: _____MEL and V/HZ adjusted____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?

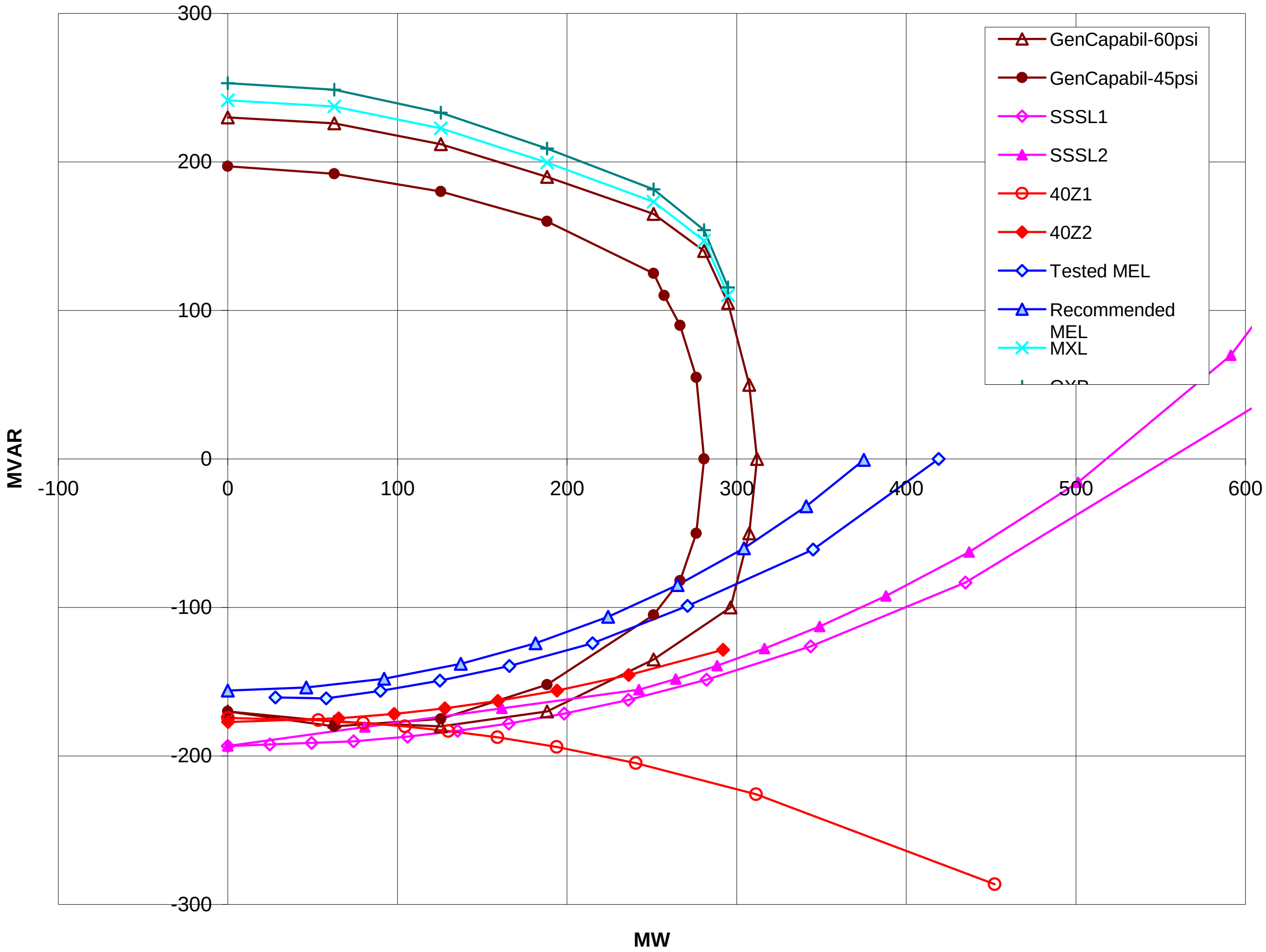
   ____

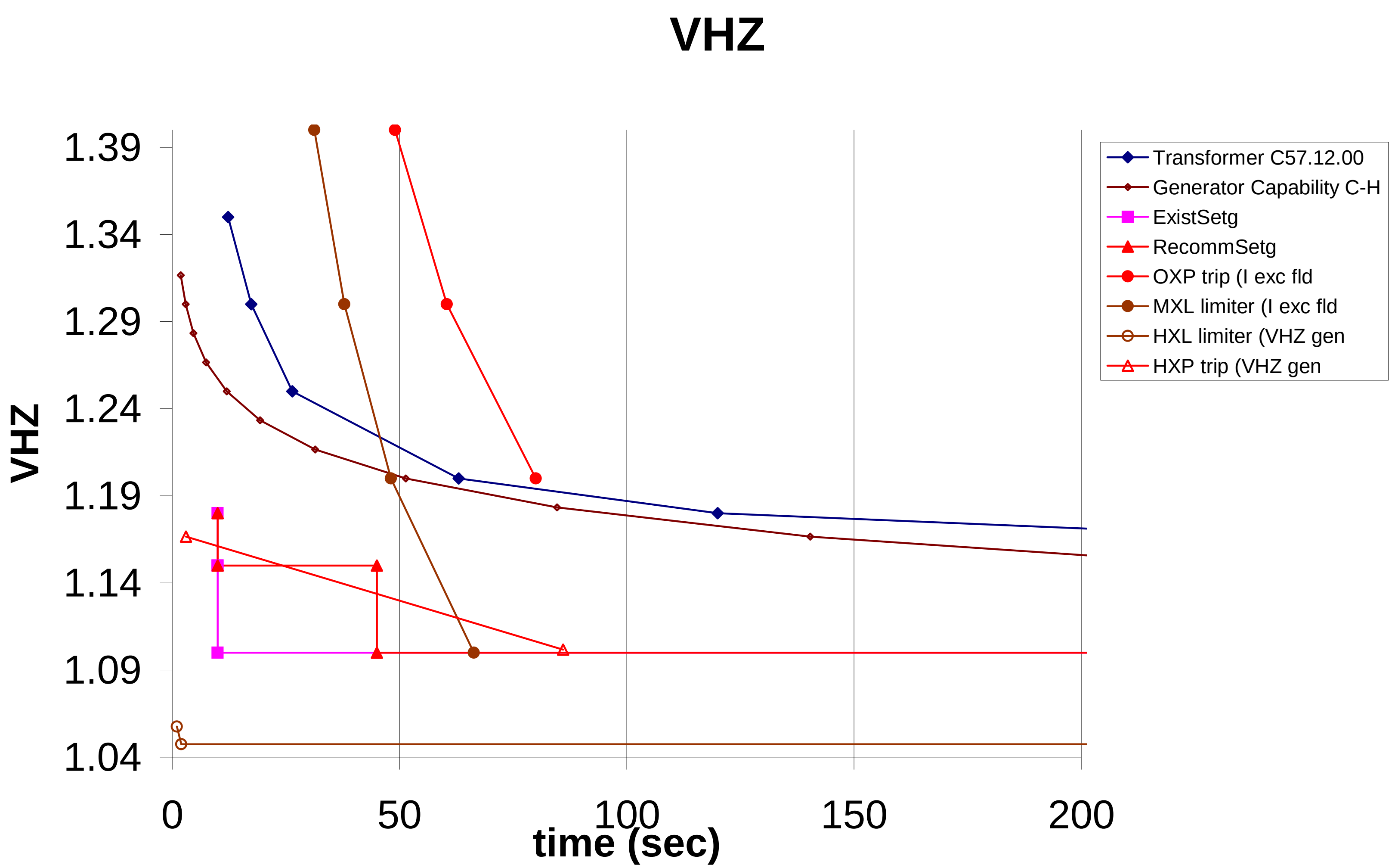
   ____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)
10. Name of person completing form: _Art Howell Phone number:281-297-3470

    Company name: Entergy

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.

Generator Capability (MW/MVAR)





VHZ
1.39
1.34
1.29
1.24
1.19
1.14
1.09
1.04
0
50
100
150
200
time (sec)
Transformer C57.12.00
Generator Capability C-H
ExistSetg
RecommSetg
OXP trip (I exc fld
MXL limiter (I exc fld
HXL limiter (VHZ gen
HXP trip (VHZ gen

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

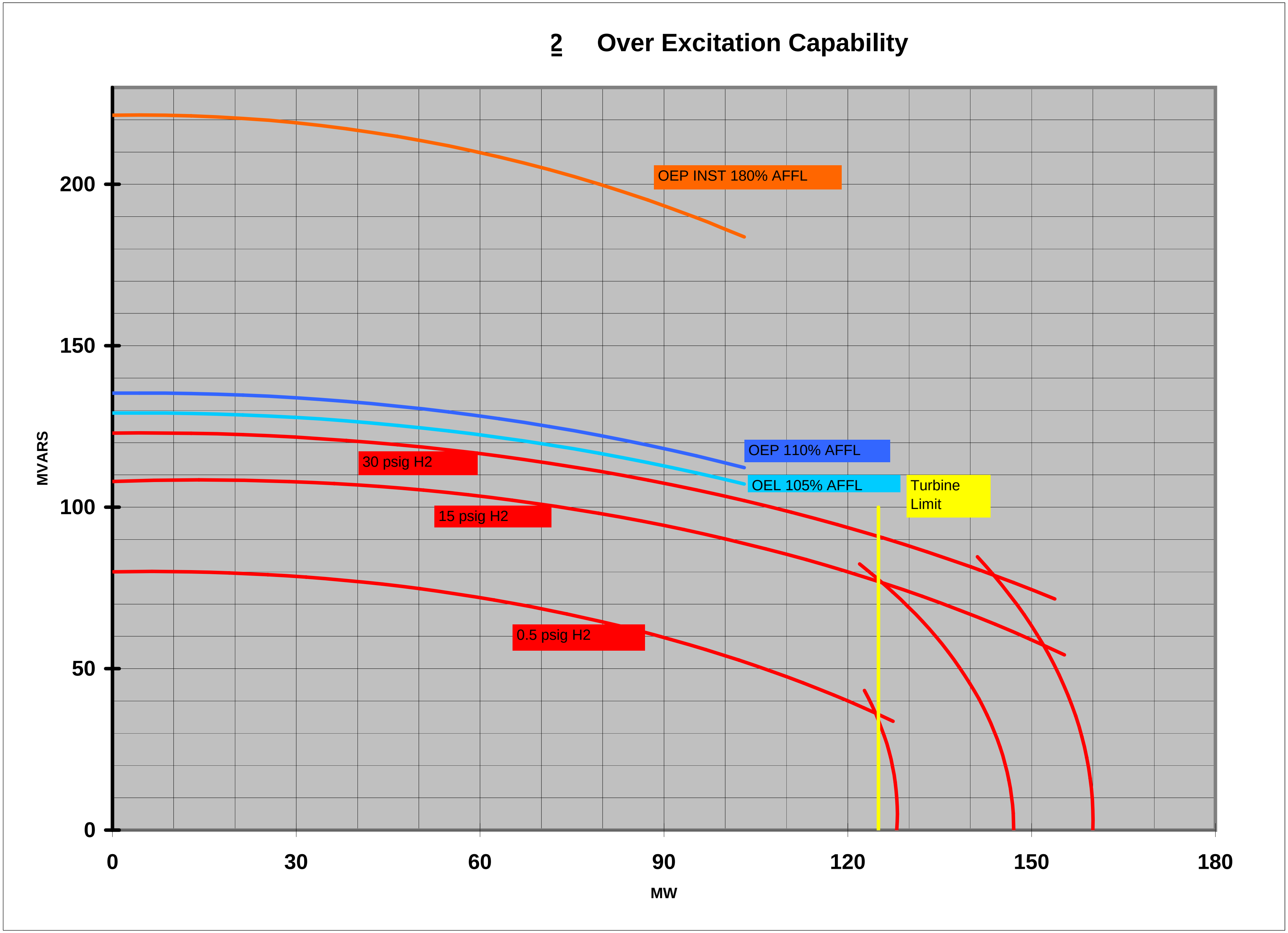
Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

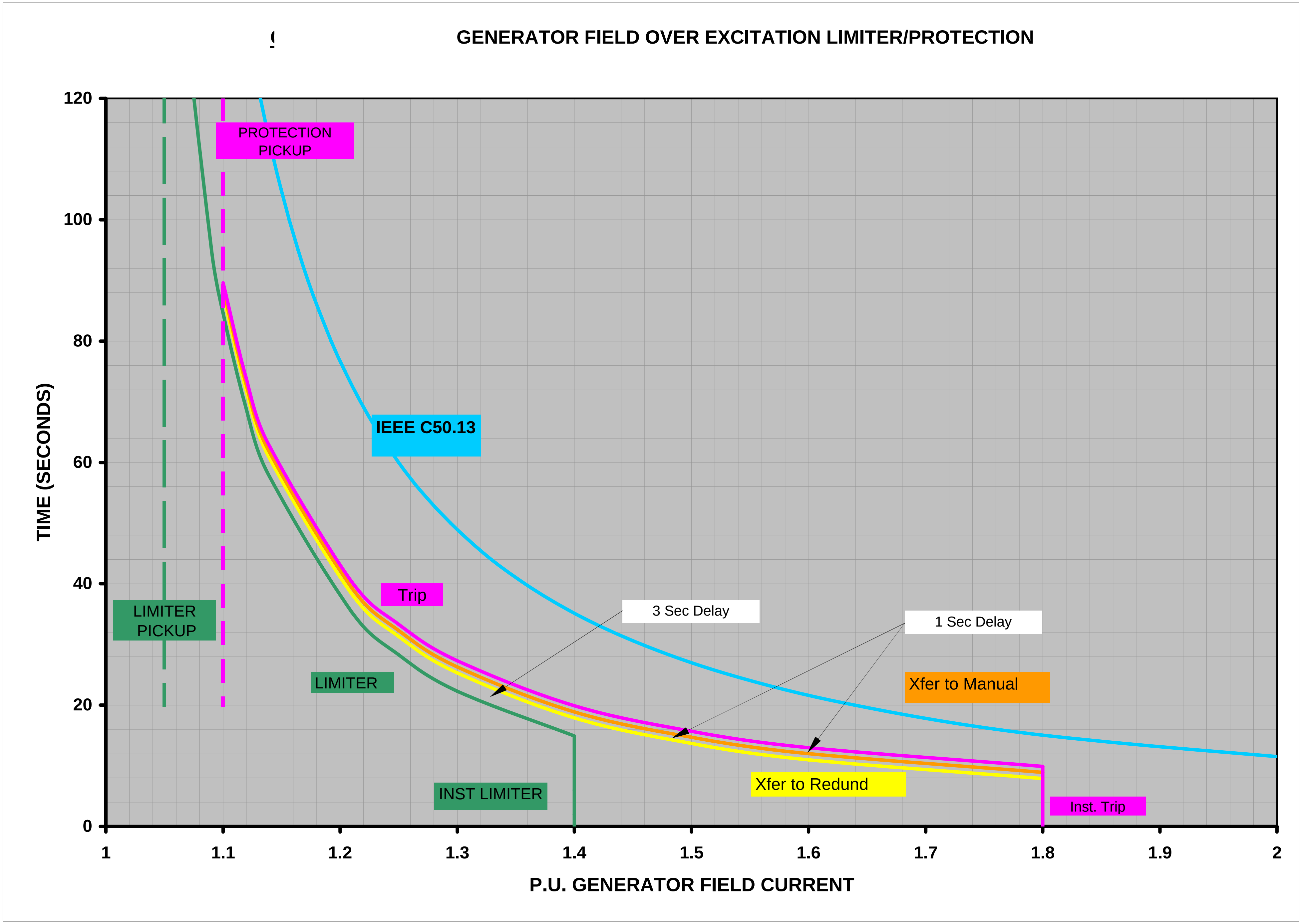
1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? ____20____ Hours
2. What methodology / tools were used to perform the coordination studies?
   - ☐ Computerized coordination curves
   - ☐ Manual coordination curves
   - ☒ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? ___80_____
4. How long did it take to analyze the technical information and draw the curves (plots)? ____80____ Hours
5. List any material costs associated with this study.
   ______minimal____
   ____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? ___Yes_____ (Yes or No)
7. If not, list the devices that needed configuration changes: ______________ Need to look more closely at volts/hertz______________________________
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
   ____
   ____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)
10. Name of person completing form: _Pat Longhsore_ Phone number _803-217-7490__

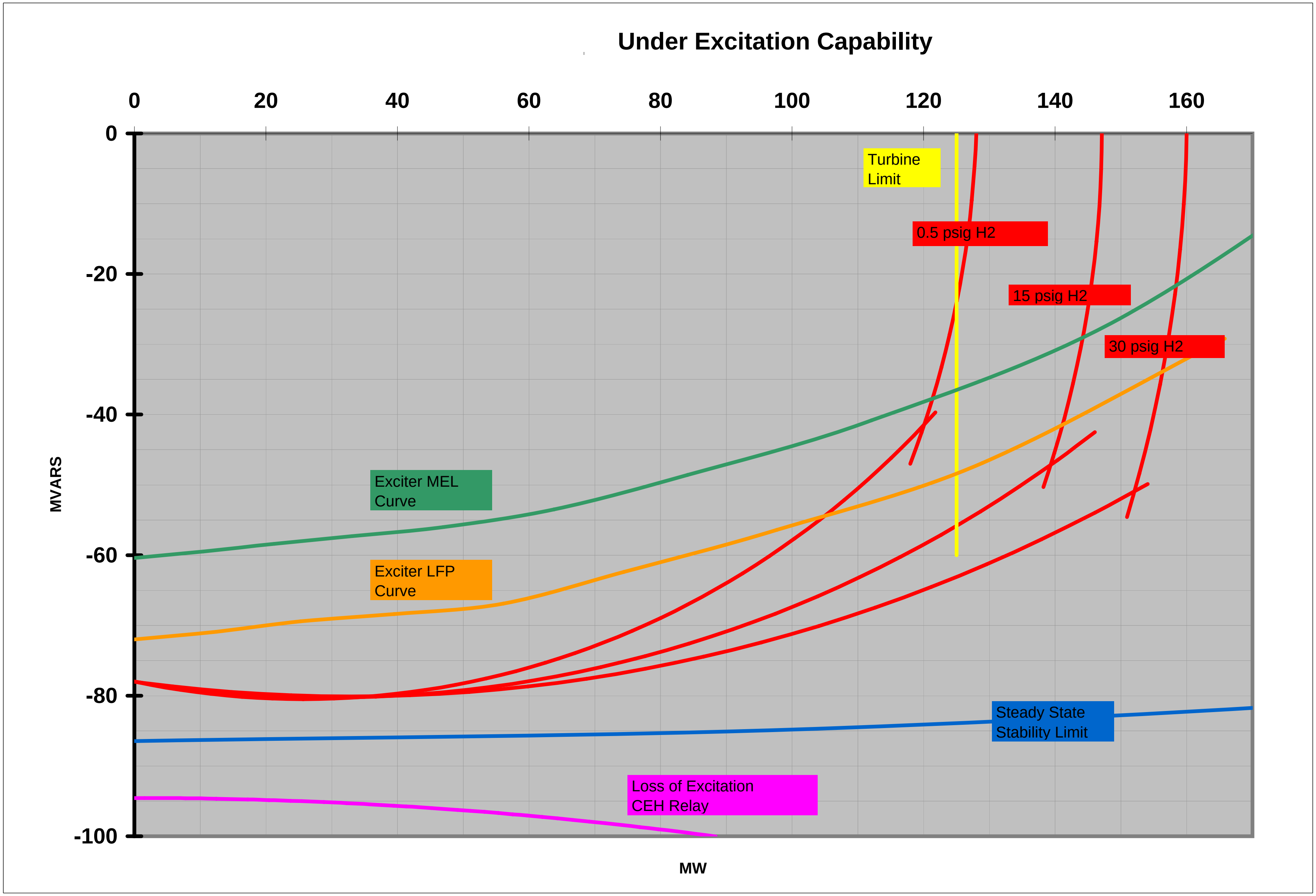
    Company name _S. C. Electric & Gas Co.______________________

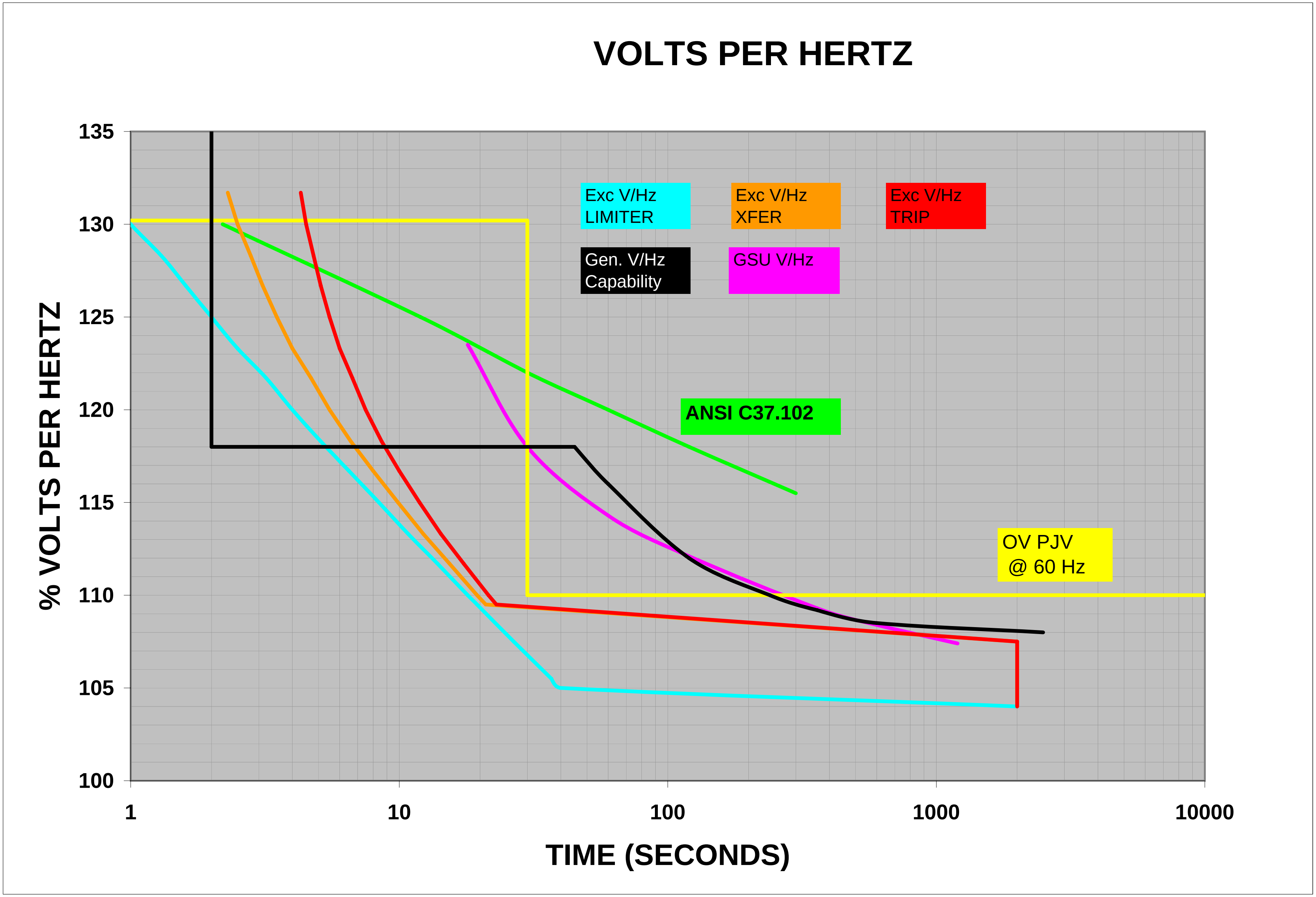
Send the completed report form and coordination curves electronically to: phuntley@serc1.org.



2 Over Excitation Capability
OEP INST 180% AFFL
OEP 110% AFFL
OEL 105% AFFL
Turbine Limit
30 psig H2
15 psig H2
0.5 psig H2
MVARS
MW
0
50
100
150
200
0
30
60
90
120
150
180


GENERATOR FIELD OVER EXCITATION LIMITER/PROTECTION
120
100
80
60
40
20
0
TIME (SECONDS)
PROTECTION PICKUP
IEEE C50.13
Trip
LIMITER PICKUP
LIMITER
3 Sec Delay
1 Sec Delay
Xfer to Manual
Xfer to Redund
INST LIMITER
Inst. Trip
1
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2
P.U. GENERATOR FIELD CURRENT


Under Excitation Capability
0
20
40
60
80
100
120
140
160
0
-20
-40
-60
-80
-100
MVARS
MW
Turbine Limit
0.5 psig H2
15 psig H2
30 psig H2
Exciter MEL Curve
Exciter LFP Curve
Steady State Stability Limit
Loss of Excitation CEH Relay


VOLTS PER HERTZ
% VOLTS PER HERTZ
TIME (SECONDS)
135
130
125
120
115
110
105
100
1
10
100
1000
10000
Exc V/Hz LIMITER
Exc V/Hz XFER
Exc V/Hz TRIP
Gen. V/Hz Capability
GSU V/Hz
ANSI C37.102
OV PJV @ 60 Hz

SERC PRC-019 Field Test Reporting Form

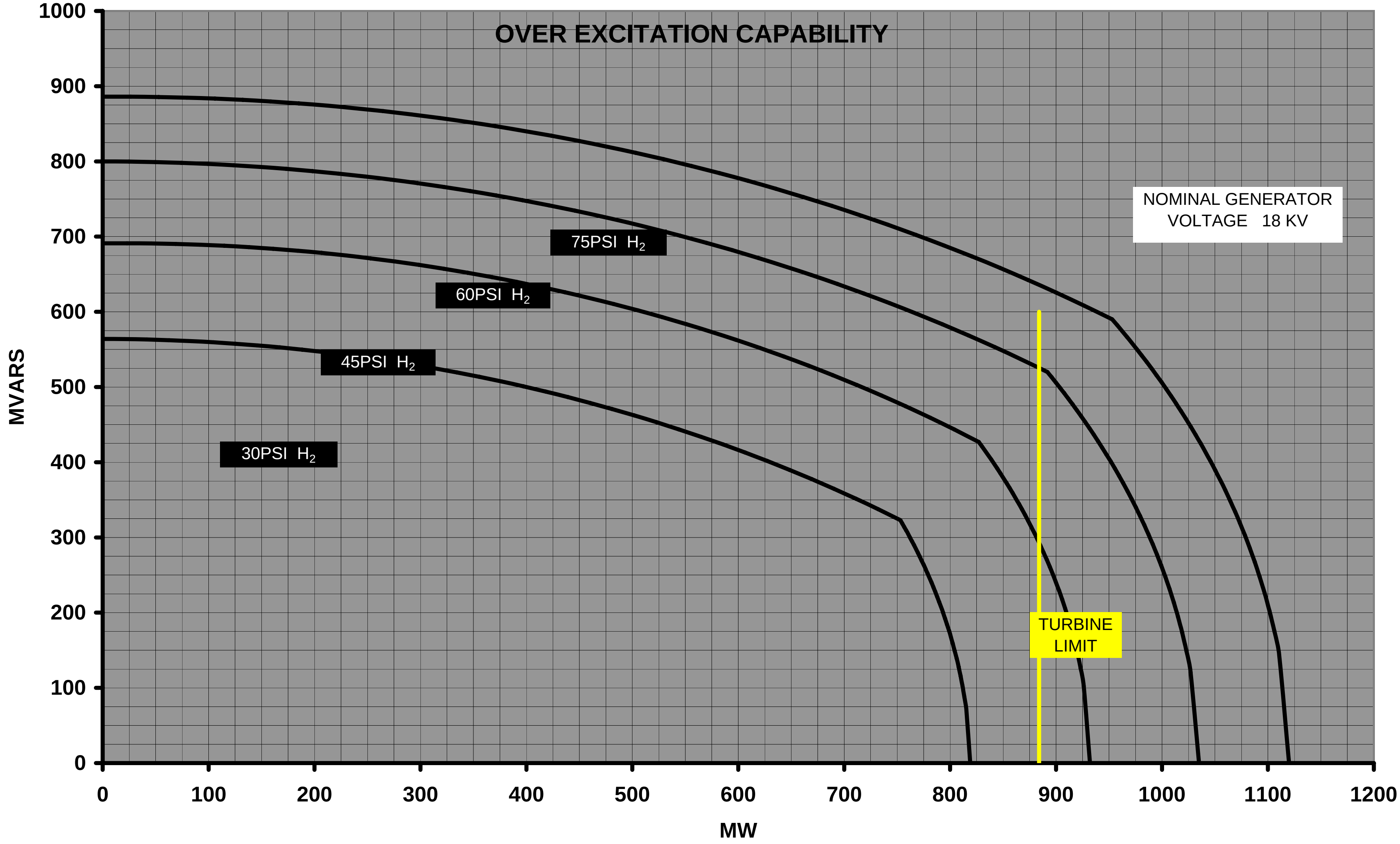
The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

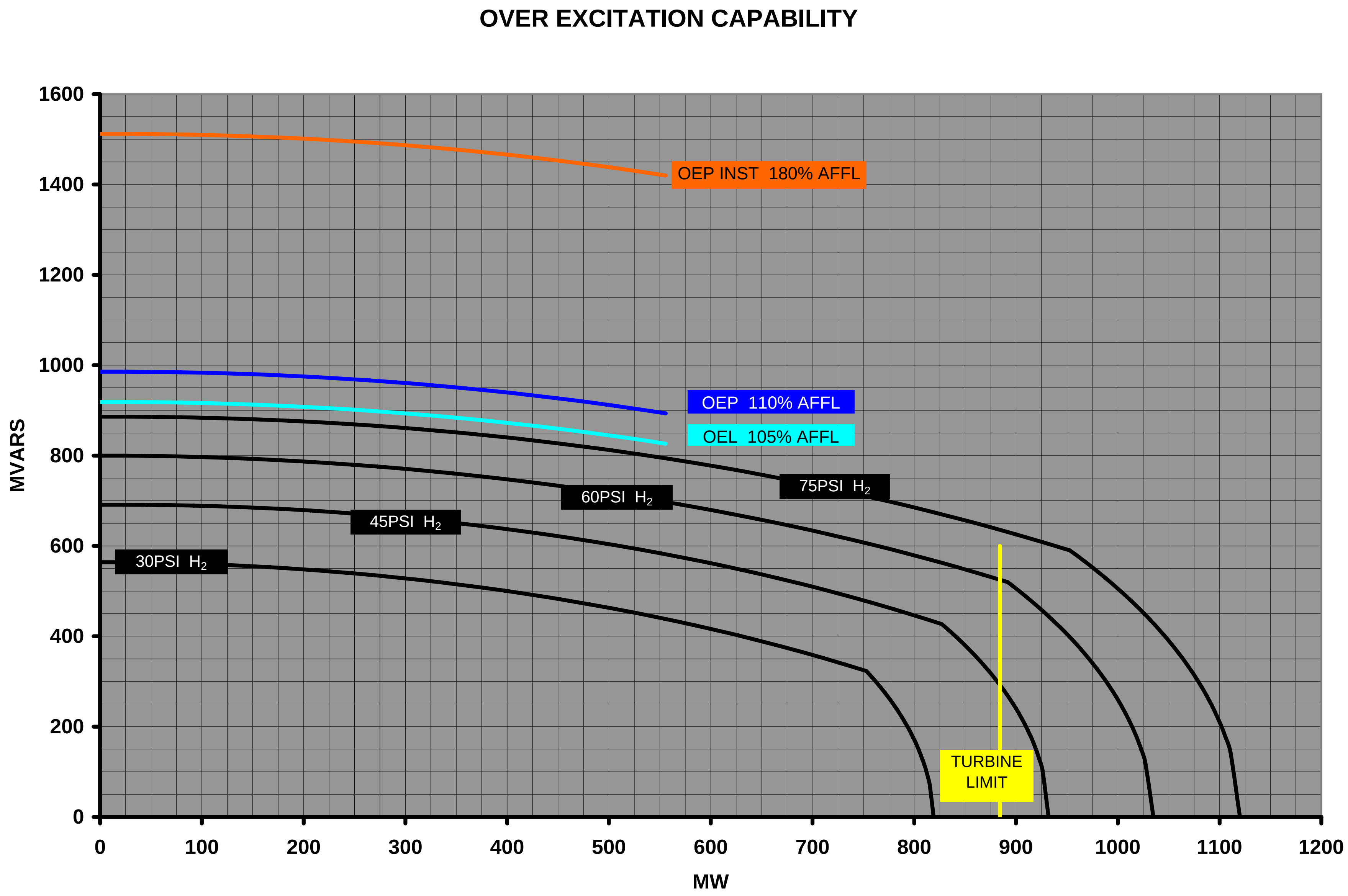
Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? 16 Hours
2. What methodology / tools were used to perform the coordination studies?
   - ☐ Computerized coordination curves
   - ☐ Manual coordination curves
   - ☒ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? 1000
4. How long did it take to analyze the technical information and draw the curves (plots)? 40 Hours
5. List any material costs associated with this study.
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? YES (Yes or No)
7. If not, list the devices that needed configuration changes:
   SOME MEL SETTING CHANGES
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)

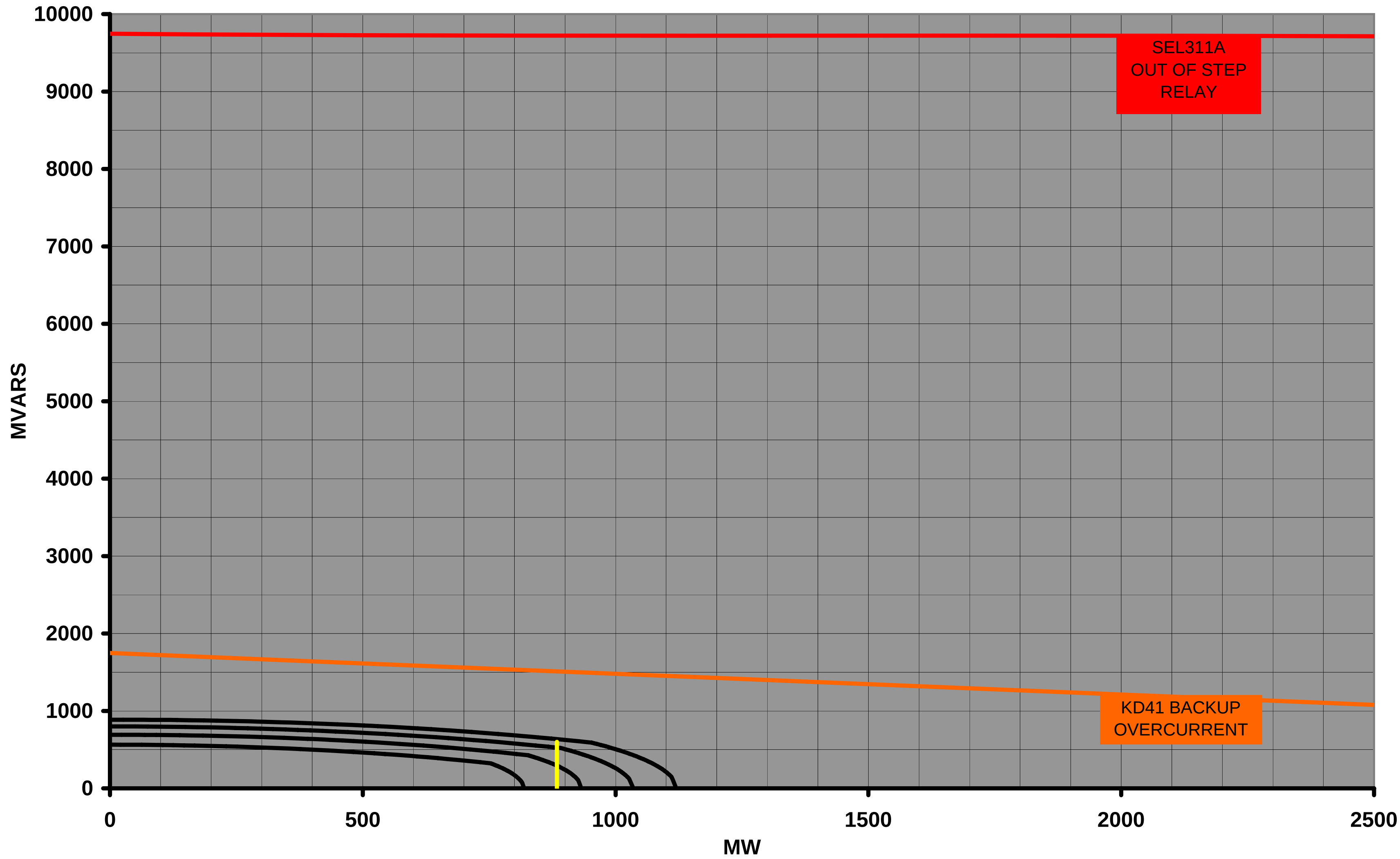
Send the completed report form and coordination curves electronically to: phuntley@serc1.org.

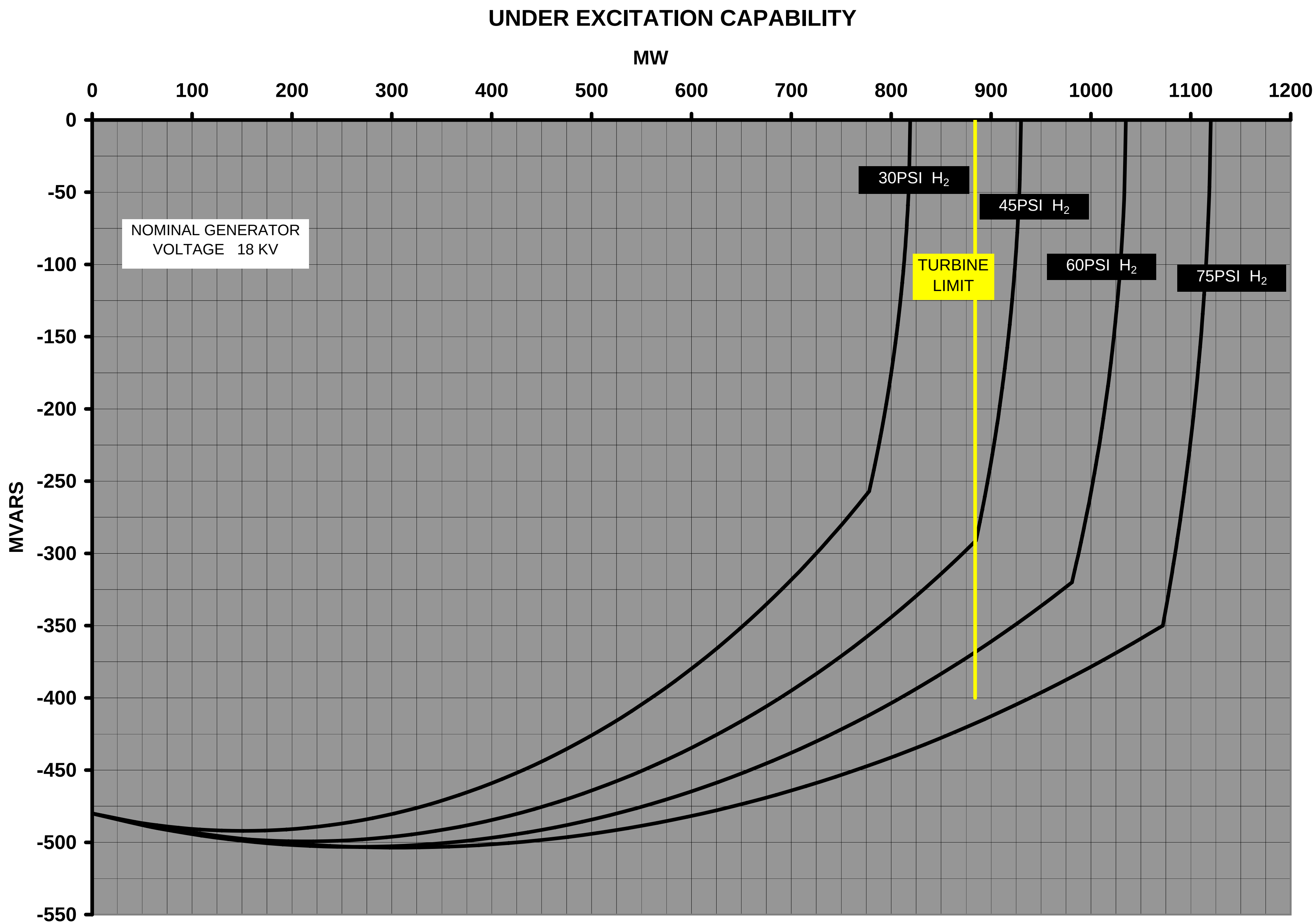

OVER EXCITATION CAPABILITY
NOMINAL GENERATOR VOLTAGE 18 KV
75PSI H_2
60PSI H_2
45PSI H_2
30PSI H_2
TURBINE LIMIT
MVARS
MW
1000
900
800
700
600
500
400
300
200
100
0
0
100
200
300
400
500
600
700
800
900
1000
1100
1200



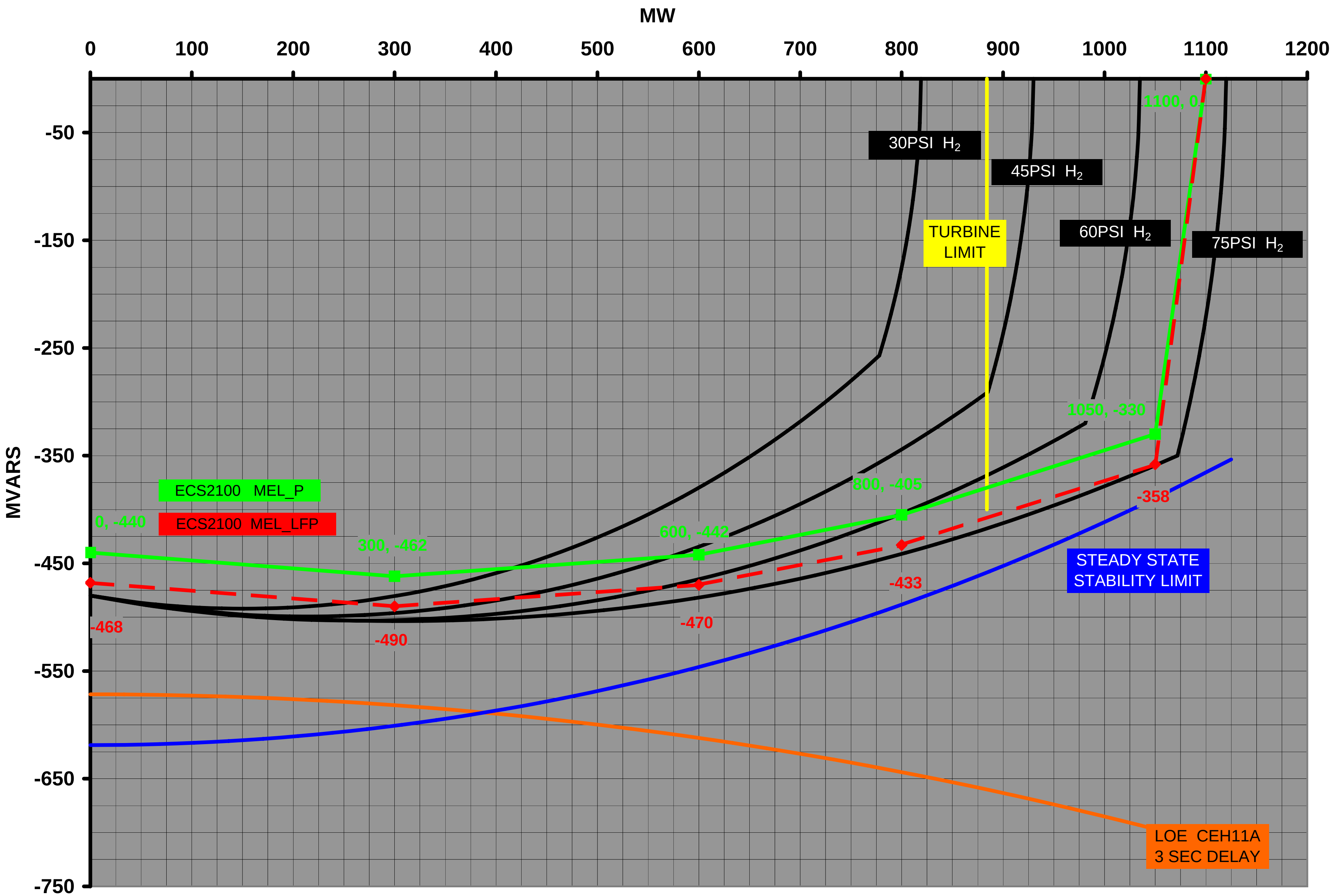
OVER EXCITATION CAPABILITY
1600
1400
1200
1000
800
600
400
200
0
MVARS
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
MW
OEP INST 180% AFFL
OEP 110% AFFL
OEL 105% AFFL
75PSI H_2
60PSI H_2
45PSI H_2
30PSI H_2
TURBINE LIMIT

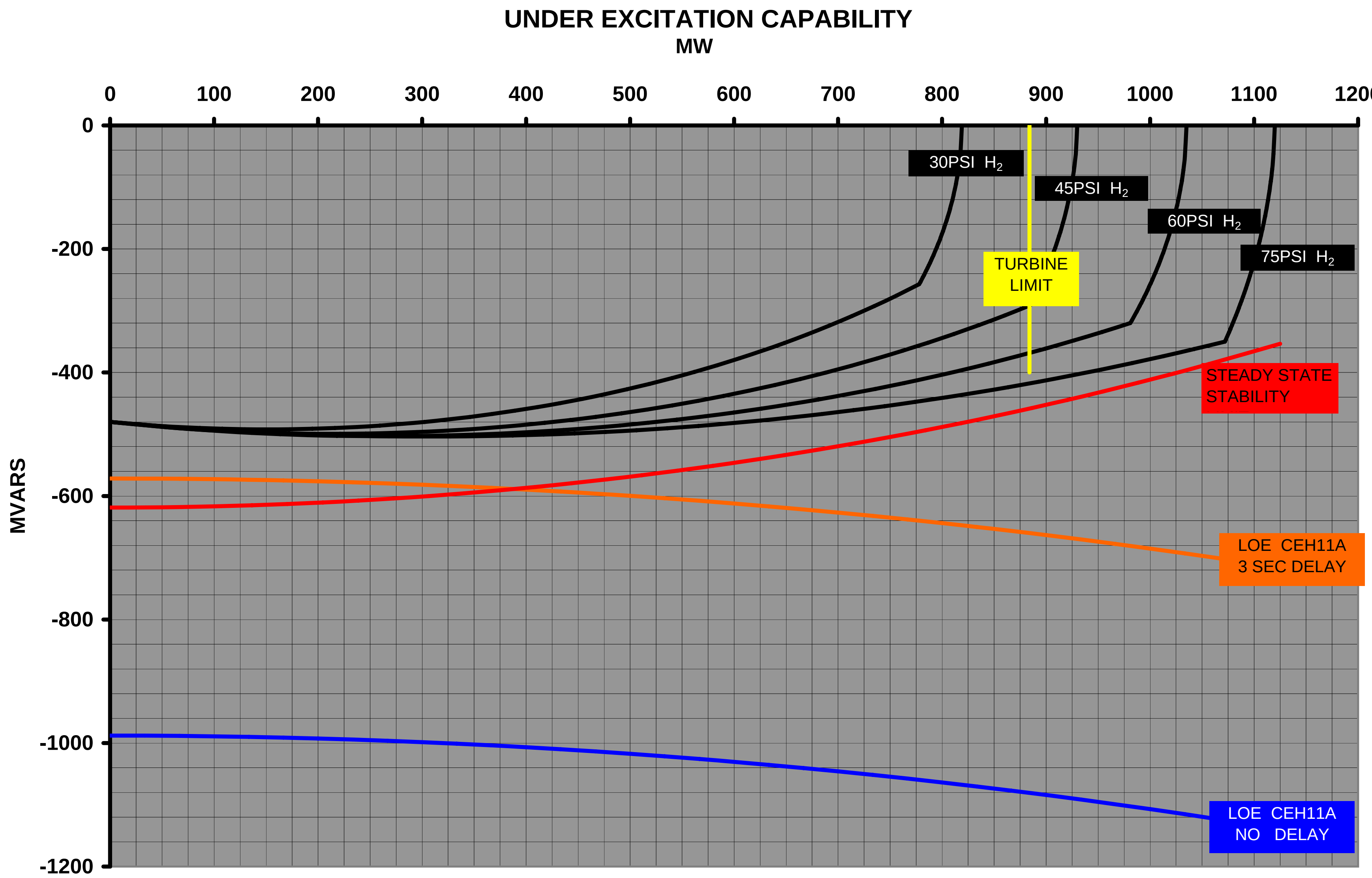
OVER EXCITATION CAPABILITY

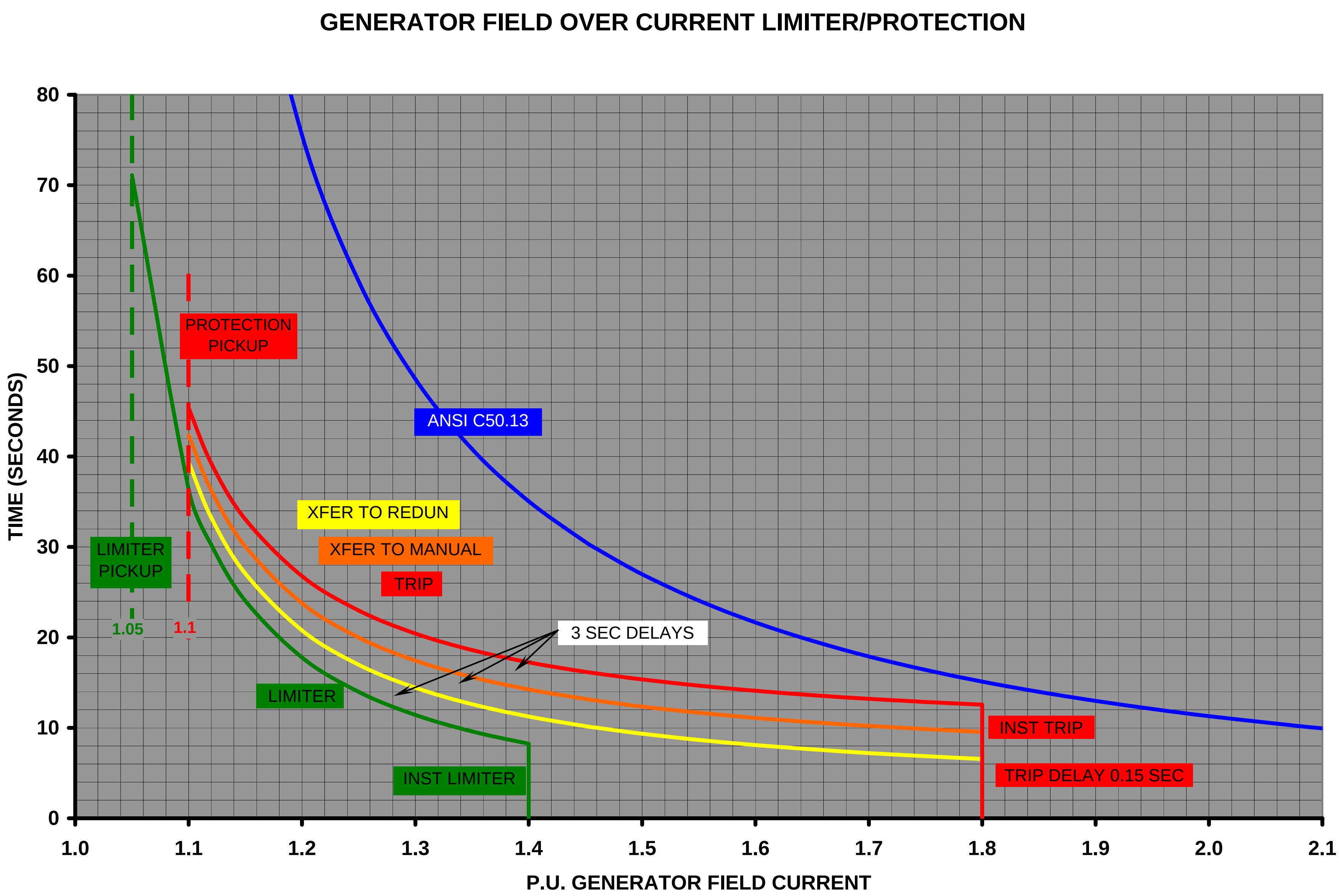


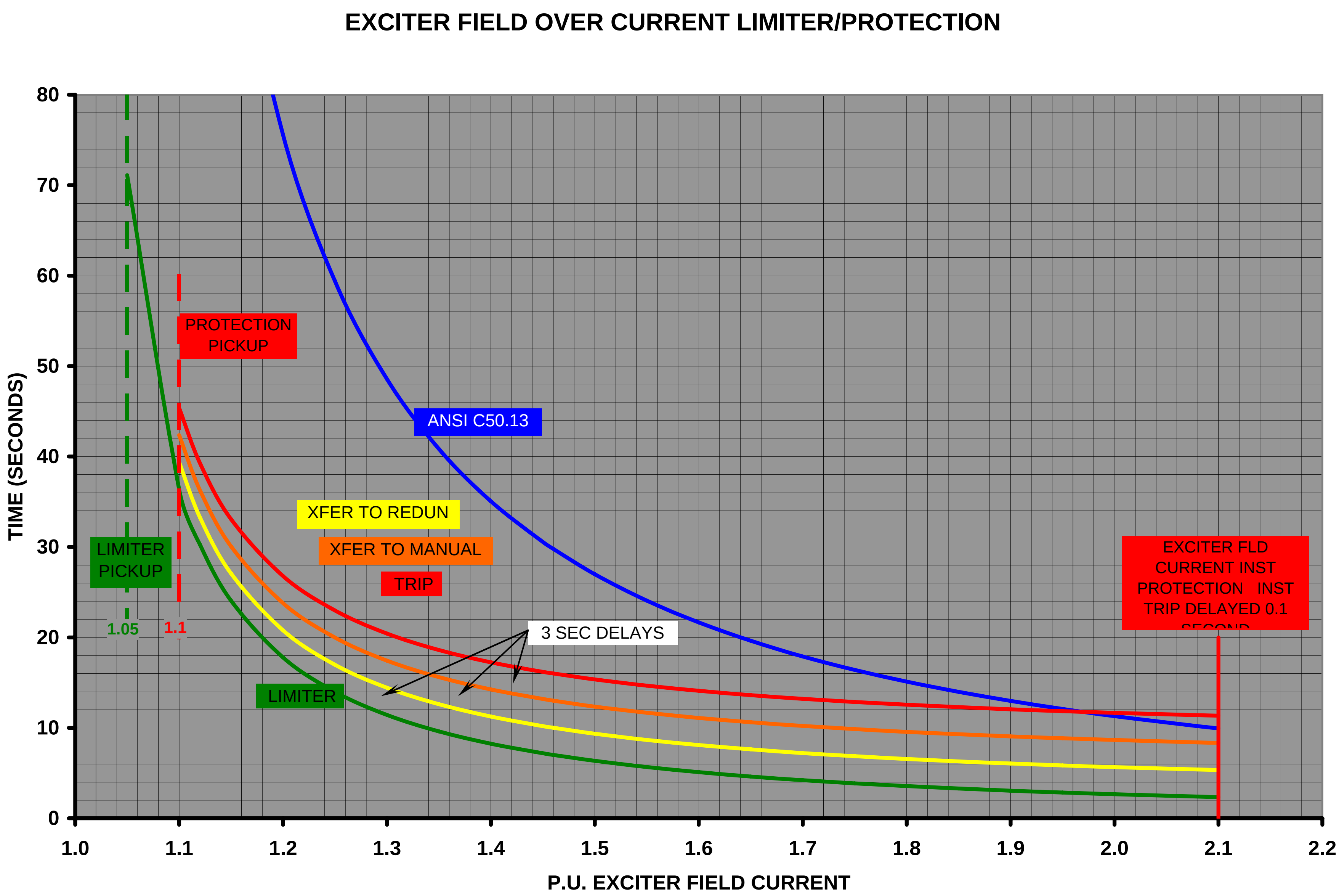

UNDER EXCITATION CAPABILITY
MW
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
MVARS
0
-50
-100
-150
-200
-250
-300
-350
-400
-450
-500
-550
NOMINAL GENERATOR VOLTAGE 18 KV
30PSI H_2
45PSI H_2
60PSI H_2
75PSI H_2
TURBINE LIMIT

UNDER EXCITATION CAPABILITY

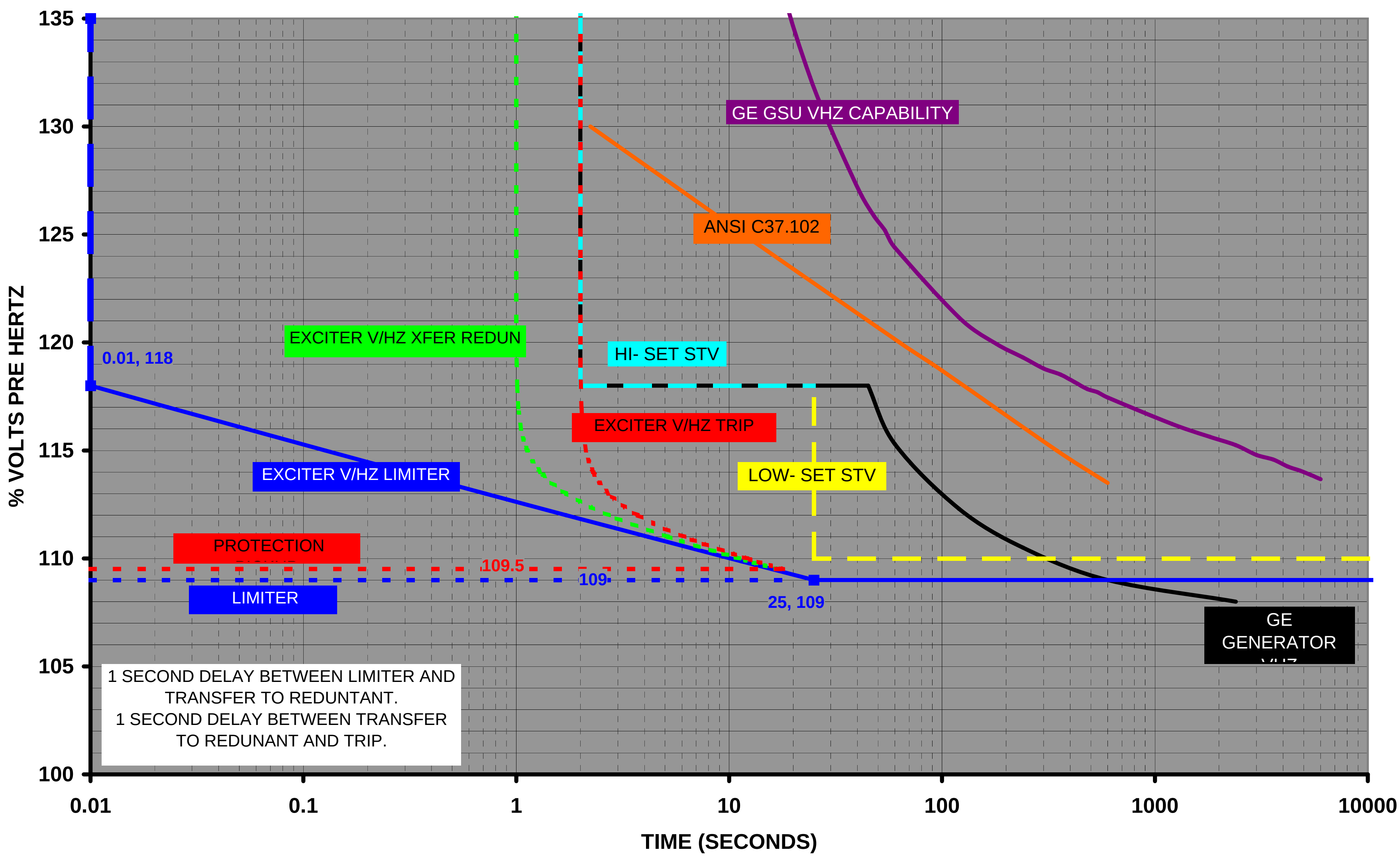


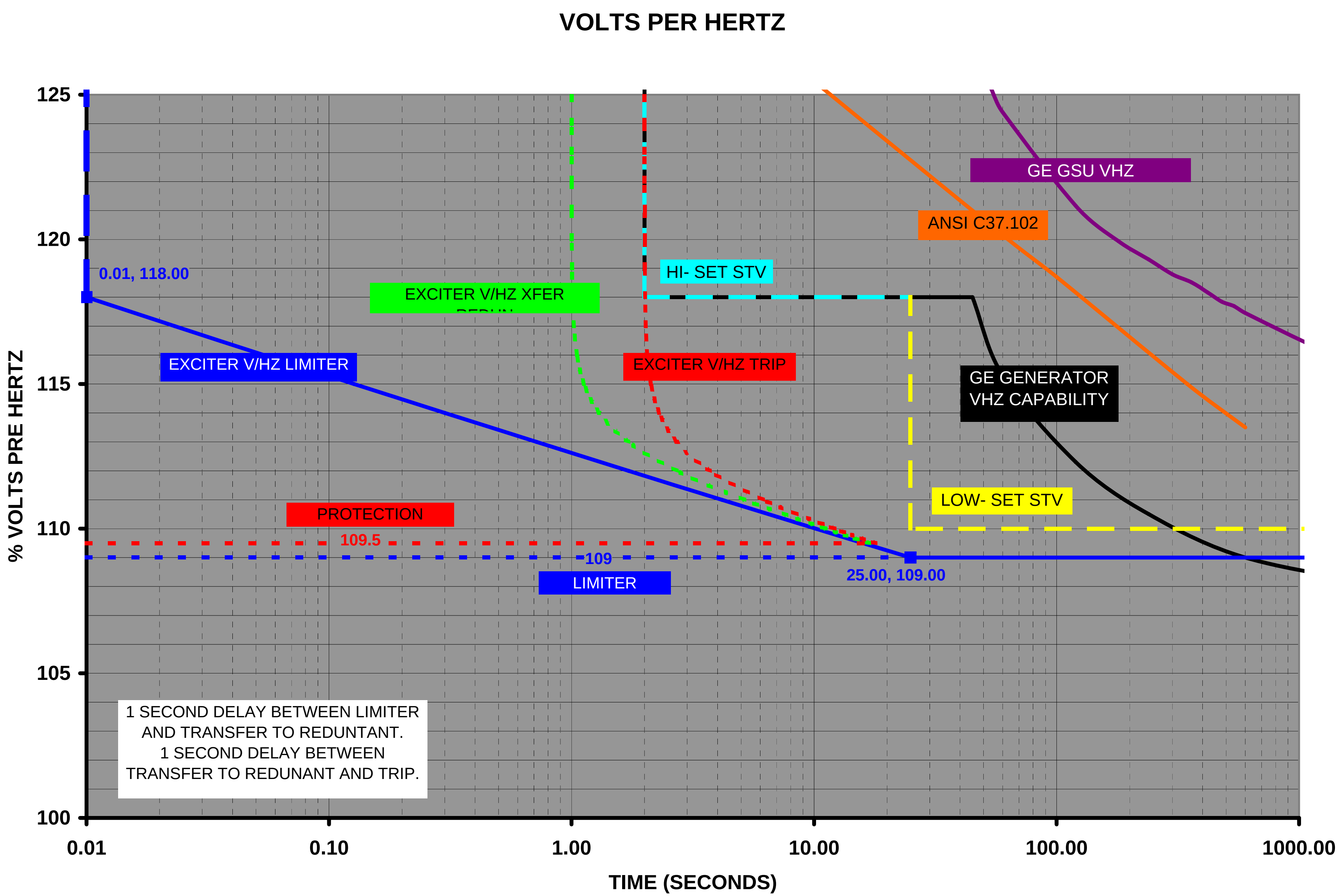

UNDER EXCITATION CAPABILITY
MW
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
MVARS
0
-200
-400
-600
-800
-1000
-1200
30PSI H_2
45PSI H_2
60PSI H_2
75PSI H_2
TURBINE LIMIT
STEADY STATE STABILITY
LOE CEH11A 3 SEC DELAY
LOE CEH11A NO DELAY


GENERATOR FIELD OVER CURRENT LIMITER/PROTECTION
TIME (SECONDS)
80
70
60
50
40
30
20
10
0
1.0
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
2.1
P.U. GENERATOR FIELD CURRENT
PROTECTION PICKUP
ANSI C50.13
XFER TO REDUN
XFER TO MANUAL
TRIP
LIMITER PICKUP
1.05
1.1
3 SEC DELAYS
LIMITER
INST TRIP
INST LIMITER
TRIP DELAY 0.15 SEC


EXCITER FIELD OVER CURRENT LIMITER/PROTECTION
TIME (SECONDS)
P.U. EXCITER FIELD CURRENT
0
10
20
30
40
50
60
70
80
1.0
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
2.1
2.2
PROTECTION PICKUP
ANSI C50.13
XFER TO REDUN
XFER TO MANUAL
TRIP
LIMITER PICKUP
1.05
1.1
3 SEC DELAYS
LIMITER
EXCITER FLD CURRENT INST PROTECTION INST TRIP DELAYED 0.1 SECOND

VOLTS PER HERTZ




VOLTS PER HERTZ
% VOLTS PRE HERTZ
TIME (SECONDS)
125
120
115
110
105
100
0.01
0.10
1.00
10.00
100.00
1000.00
0.01, 118.00
EXCITER V/HZ LIMITER
EXCITER V/HZ XFER
HI- SET STV
EXCITER V/HZ TRIP
GE GSU VHZ
ANSI C37.102
GE GENERATOR
VHZ CAPABILITY
LOW- SET STV
PROTECTION
109.5
109
LIMITER
25.00, 109.00
1 SECOND DELAY BETWEEN LIMITER
AND TRANSFER TO REDUNTANT.
1 SECOND DELAY BETWEEN
TRANSFER TO REDUNANT AND TRIP.

Attachment 6
PRC-024 Test Results

- **SERC PRC-024 GO Field Test Reporting Form - COE 6-8-2007.pdf**
- **SERC PRC-024 Field Test Reporting Form Dominion June 7 2007.doc**
- **Dominion Voltage Excursion Example.pdf**
- **SERC PRC-024 GO Field Test Reporting Form (SCG 6-8-07 Rev 0).doc**
- **PRC-024_SS (SCG 6-8-07).pdf**
- **PRC-024_Dynamics (SCG 6-8-07).pdf**
- **Additional Comments PRC-024 June 11,2007.doc**
- **SERC Voltage Ride thru Attachment A.doc**
- **SERC Voltage Ride thru Attachment B.doc**

Generator Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? 8 Hours
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☒ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic.
4. How many man-hours did it take to develop the methodology / tools? 4
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic? ☒Yes ☐ No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? 2Hours
7. List any material costs associated with the generator frequency withstand capability portion of this field test. Curve ploting software $1,810.
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☒ Combination (computerized / manual)
10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic.
11. How many man-hours did it take to develop the methodology / tools? 16

12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☒Yes ☐ No Note: The current Unit and Bus under voltage relay settings will ride through the draft LVRT curve. Presently our organization does not have sufficient data to determine if the current excitation and AVR settings will ride through the draft LVRT curve.

    If no please attach additional information as appropriate.

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? Hours

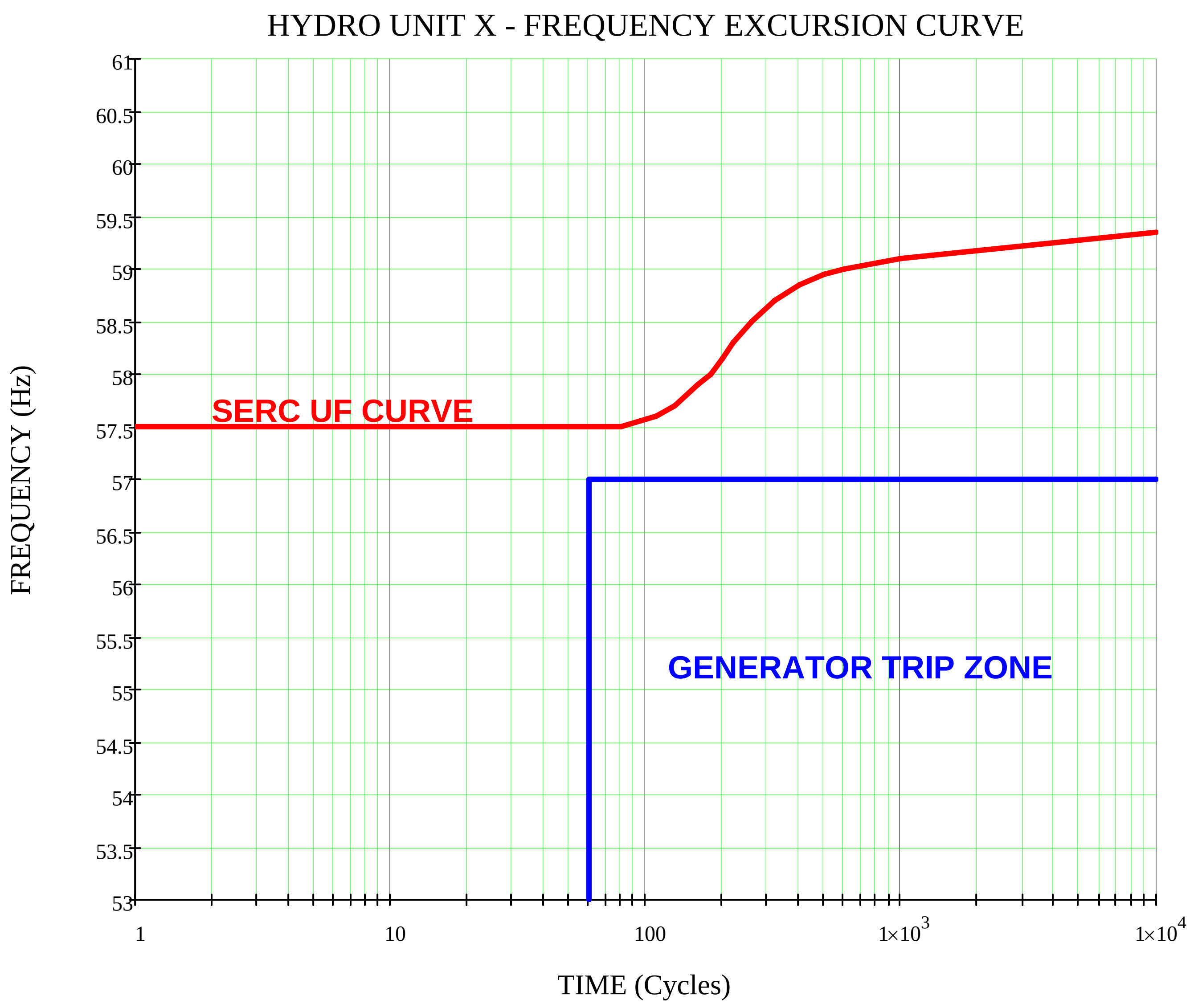
14. List any material costs associated with the generator LVRT capability portion of this field test. Curve ploting software $1,810.

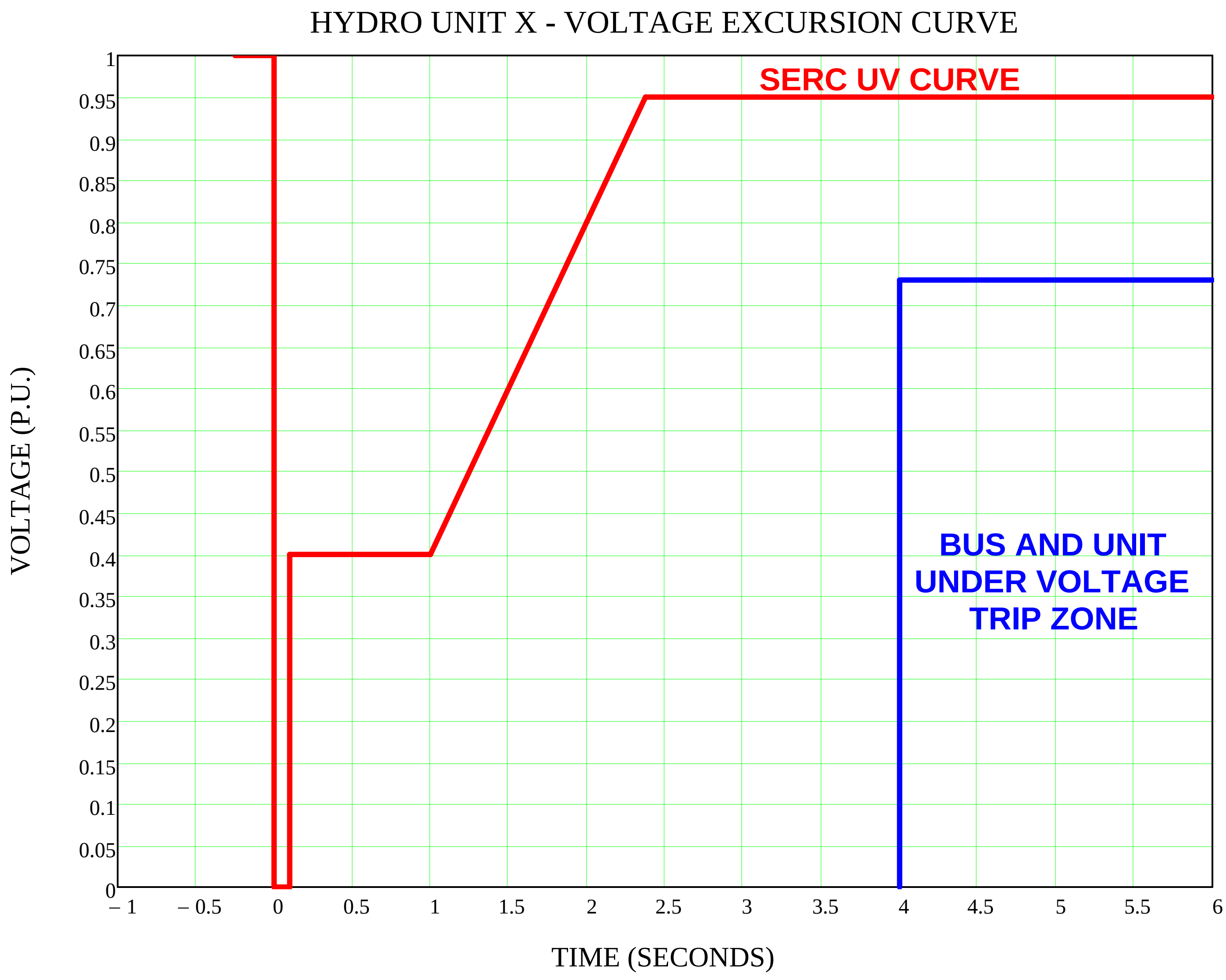
15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc). See attached.

17. Name of the person completing the form: David Williams Phone Number 706.643.0313 Company Name Corps of Engineers - Mobile District

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**


HYDRO UNIT X - FREQUENCY EXCURSION CURVE
FREQUENCY (Hz)
61
60.5
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
53.5
53
SERC UF CURVE
GENERATOR TRIP ZONE
1
10
100
1×10^3
1×10^4
TIME (Cycles)


HYDRO UNIT X - VOLTAGE EXCURSION CURVE
SERC UV CURVE
BUS AND UNIT
UNDER VOLTAGE
TRIP ZONE
VOLTAGE (P.U.)
TIME (SECONDS)
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0.6
0.55
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
− 1
− 0.5
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6

Generator Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? **2 Hours**
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic. **Most of our generating units would be tripped manually during frequency excursions. Each control room has three Annunciator alarms for frequency changes; 59.8 Hz, 58.1 Hz, and 57.6 Hz. The 59.8 Hz alarm alerts the control room operator (CRO) that there is an issue with the frequency. The CRO will manually trip the unit if the frequency is at 58.1 Hz for 30 seconds or at 57.6 Hz for 1 second.**
4. How many man-hours did it take to develop the methodology / tools?
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic? ☐ Yes ☒ No

   If no please attach additional information as appropriate. **See number 15**.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? **0 Hours**
7. List any material costs associated with the generator frequency withstand capability portion of this field test. **$0**
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)

Generator Owner PRC-024 SERC Field Test Reporting Form

10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic. **One of our relay engineers evaluated the characteristics of the back-up impedance relay. Determined that the generating unit would not stay on line for a voltage profile shown on the "Proposed SERC Generator Voltage Excursion Curve". Also, see the attached example showing that other types of generating unit equipment can force a unit off line during voltage excursions.**

11. How many man-hours did it take to develop the methodology / tools? **1 hour**.

12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☐ Yes ☒ No

    If no please attach additional information as appropriate. **See number 15.**

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? **2 Hours**.

14. List any material costs associated with the generator LVRT capability portion of this field test. **$0**

15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

<u>Proposed UF Excursion Curve</u>:

After a review by our turbine engineers and equipment vendors, the operating limits for frequency excursions could possible be adjusted to comply with the proposed curve.

<u>Proposed UV Excursion Curve</u>:

I suggest that the implementation of this standard be delayed until:

- **A.** **Industry specialists analyze, develop, and provide a method(s) for reviewing generating equipment and protective relay characteristics to guide generator operators on how to comply with the proposed standard.**
- **B.** **A cost benefit analysis should be performed to determine the most economical and logical way to achieve the desired end result; should generator owners perform engineering studies and equipment/protective relay changes or should transmission owners/planners/operators change the system models and/or install new transmission equipment/relays or both?**

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

17. Name of the person completing the form: **Larry Whanger** Phone Number **804.273.3576** Company Name **Dominion.**

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

Generator Owner PRC-024 SERC Field Test Reporting Form

Note: See the attached example of what actually happened during a voltage excursion at one of our power stations.

Fossil & Hydro Technical Services

TECHNICAL REPORT

[redacted]

Loss of Generation

Due to

Transmission Fault Event

Technical Report
Loss of Generation Due to Transmission Fault

1. EXECUTIVE SUMMARY

This report is prepared due to an event that occurred on January 31,2006 that caused three of four generating units at the [redacted] to trip. The event that took place involved a rare type of fault combined with a rare equipment failure. The fault that occurred suppressed the voltage at the station and the circuit breaker failure prolonged the duration of the event to the extent that station equipment malfunctioned and could not be overcome before most of the generating units were lost.

This Technical Report provides data calculated by the Transmission Department reflecting a fault study and the associated Voltages that can be expected to occur at the [redacted] Switchyard for various fault scenarios. Using this data, and reliability data published in the IEEE Std 493 (Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems) for similar equipment and faults, the probabilities associated with different events are calculated. Each such event, will cause varying degrees of Voltage Sags and impacts to the Station Auxiliaries Electrical System and operating Units.

The impacts from various fault conditions for each transmission line are projected in a somewhat subjective manner based on the prior impact and expected operating conditions that will occur and the lack of a uniform standard for equipment tolerance to Voltage Sag events for which to base a solid predictive model. These impacts are based on traditional design philosophies of power stations in general, and a full detailed assessment and testing program are required to improve the confidence factor of these assessments.

The costs of Generation losses resulting from an event on the Transmission system are calculated by using replacement power costs for the year 2006, averaged across all four units with each unit at maximum capacity, multiplied by the various probabilities and the expected impact that each event occurrence should produce. The expected annual costs for this type of event is [redacted].

Based on the Reliability Data published, and the characteristics of the transmission lines connected, the transmission lines connected to [redacted] should expect 4.06 outages (momentary or sustained) per year.
The cost of replacement power for all units is based on a six-hour loss for each for a combined total of 3750 MWH at [redacted].

Recognizing that the most economical alternatives for corrective action should be focused at specific equipment, recommendations are offered for the known equipment and suggestions regarding testing techniques are provided for the unknown equipment. Future critical equipment upgrades should include voltage tolerance requirements as part of the equipment specification and as conditions warrant.

Other factors for future consideration that are beyond the scope of this report, include Voltage Profile Studies of the Station Auxiliary Electrical System to determine that all transformers are being operated at their optimum taps, and Switchyard upgrades that may improve specific risks, but at increased costs.

2. INTRODUCTION

On January 31, 2006, the [redacted] sustained a voltage sag of approximately 45% for 26 cycles as indicated in the attached exhibits. The voltage sag resulted from a double line to ground fault caused by a lightning strike approximately 6.9 miles from the station on Line 164. The terminal Breaker at Reeves Ave substation failed to trip and initiated the Breaker Failure Scheme. As a direct result, the power station lost three of four generating units that were operating at the time.

2.1. Purpose

One objective for this document is to provide some insight and understanding regarding the previous event, and understand the consequences/probabilities of future events.

Another objective is to determine the risk of exposure to a similar event that will happen in the future, identify weaknesses in the existing protection against these events. Recommend measures that may be appropriate to mitigate these risks and to quantify these measures by providing an economic evaluation based on the likelihood of experiencing a future event.

2.2. References

The following publications have been used to derive data and information

ANSI/IEEE Std 493-1997 493 Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems
ANSI C84.1-1982 American National Standard for Electric Power Systems and Equipment (60 Hz)– Voltage Ratings
ANSI/IEEE Std 666-1991 Design Guide for Electric Power Service Systems for Generating Stations
ANSI/IEEE Std 1159-1995 IEEE Recommended Practice for Monitoring Electric Power Quality

3. [redacted] UNIT TRIPS

The following information is based on a report issued by the station concerning the events that occurred January 31, 2006

[redacted] summary of events observed/recorded for each unit, 01/31/06

At approximately 06:21:15 a line fault occurs in the system (at Reeves Ave). 115KV voltage at [redacted] substation drops to about ½ (~65KV) for 4 cycles and does not fully recover for at least 26 cycles; total time about ½ of a second. See Exhibit 1.

The affect on each of the generating unit is reproduced from a station report repeated here.

3.1. Unit 1

06:21:15 (PI) All 3 coal feeder motors in service stopped running (480V feed to Merrick controls). No alarms are received in the control room. Running status was not removed in logic. Approximately 1.5 minutes after motors stop the unit trips on loss of flame scanners, black furnace.

3.2. Unit 2

06:21:15 (PI) All 3 coal feeder motors in service stopped running (480V feed to Merrick controls). No alarms are received in the control room. Running status was not removed in logic. Approximately 1.5 minutes after motors stop the unit trips on loss of flame scanners, black furnace.

Note: The coal feeder running status issue was verified on restart of unit 2 A mill feeder. The feeder motor stopped but no notification to the control room operator occurred. The feeder running status was still 'proven' but the motor was not on. If the feeder status worked correctly the units' would have tripped on 'loss of fuel' and not 'black furnace'. Removal of all fuel sources to the boiler is an MFT condition.

3.3. Unit 3

06:21:15 (SOE) 'C' coal feeder motor stopped (480V supply). Coal feeder stopped is recorded on the sequence of events recorder (SOE). The unit goes into runback mode after approximately 2 minutes due to loss of fuel from 'C' mill. The Control Room operator who was consumed with unit 4's related issues determines that unit 4 is not recoverable and switches attention to unit 3 and recovers the unit.

The unit 3 turbine board recorder reboots due to the electrical fault as indicated by loss of turbine data in PI.

3.4. Unit 4

3.4.1. 06:21:15 (SOE) 'C' coal feeder not running (480V supply to speed controller)

3.4.2. 06:21:15 (PI) BFPT main LO pump stopped (480V motor)

3.4.3. 06:21:15 (PI) 'A' dil. air fan on the SCR stopped (480V motor)

3.4.4. 06:21:16 (SOE) 'C' coal feeder running. It appears that the fault knocked 'C' feeder motor out but it came back due to a maintaining contact to run from Modicon.

3.4.5. The feeder speed in PI drops in half and then recovers.

3.4.6. 06:21:16 (SOE) BFPT tripped. The BFPT tripped after the BFPT main LO pump motor stopped. The Aux LO pump and DC back up pump started within two seconds of the main pump stopped. The Aux pump did not catch the autostop oil pressure from dropping below 60 psi. At 60 psi the low autostop oil pressure switches tripped the BFPT.

3.4.7. 06:22:29 (SOE) Low Drum Level Trip

3.4.8. 06:24:18 (SOE) Unit is taken off line by the CRO (opened breakers). The turbine solenoid trip was at 06:22:29, throttle valves recorded closed at 06:22:30.

3.5. Root Cause of Motors Stopping

The probable cause of the various motors stopped was the large drop in system voltage which also dropped the units' 480V buses to either drop out motor starter contactors or fault motors due to a voltage drop below minimum required running voltage.

5. STATION EQUIPMENT

5.1. Industry Standards

IEEE Standard C84.1 establishes Nominal voltages for Power System Equipment and also defines recommended ranges for equipment to operate. Voltage tolerance limits are based on the ANSI/NEMA MG-1, which established the criteria for standard induction motors at +/- 10% of nameplate ratings 230V, 460V, etc. Since motors represent a large component of utilization equipment, they were given primary consideration in establishing the standard. However, there is no national standard that requires particular immunity for voltage sags that may occur on the system. Some specialized interests such as the semi-conductor industry have established specification criteria for tolerance against Voltage Sags for equipment manufactured for their plants (See Exhibit 11).

It should be noted that Generating Stations are not typical in regard to the Voltage Sags that equipment should be expected to operate satisfactorily. Generating station Voltage Limits have always required tolerance against the starting duty of very large motors connected to the system, and consequently, design criteria is to allow starting of this large equipment without dropping out relays and contactors for lower voltage motors and equipment. It is also acceptable to have lower voltages because of the high degree of instrumentation used to monitor process conditions. Most station equipment originally installed with the unit should continue to operate with Voltage sags to 75 – 80% of nominal voltage.

5.2. Equipment Vulnerable to Voltage Disturbances

Equipment that is most vulnerable to voltage disturbances include solid state equipment including Control equipment specifically DCS and PLCs, Soft Start Motor Controllers, and Adjustable Speed Drives. To a lesser degree, electromechanical components such as relays, solenoids and contactors, since these all react slightly slower due to the inherent energy storage characteristics.

The ability of an individual piece of equipment varies from manufacturer to manufacturer. The Voltage Ride-through times must be evaluated for eash specific equipment suspected of being sensitive to the voltage variation.

Some examples of typical equipment –

- Solenoids 10% overvoltage and 15% undervoltage.
- Control Relays and Motor contactors are required by standrds to operate at + 10% and –15% voltage, however most will hold in down to 65% and some event to 50%.

5.3. Techniques for Improving Tolerances to Disturbances

Three-phase equipment is less susceptible to transmission events than single-phase equipment and while most power station equipment is supplied from three-phase sources, there are some equipment supplied from single-phase systems including panels feeding instruments and controls.

Control Transformers used for motor control, if oversized, provide better ride-through capability for the motor contactor. Control Transformers located in the same MCC should be connected to alternating primary phases, A-B, B-C, C-A, to reduce the chances of losing all of the equipment as opposed to just a third of the equipment.

Constant Voltage Transformers (CVT) also known as ferroresonant transformers can provide an economical solution for small loads which are fairly constant.

All solid state controls and instrumentation equipment such as embedded controllers within a equipment package should be fed from the UPS if the equipment is critical to production.

5.4. Specific Recommendations for Limited Station Equipment

Test and verify alarms from Coal system weigh feeders
This testing should incorporate the validity of an alarm, for example, a Weigh Feeder flow alarm should incorporate or prove both, conveyor movement and load. Models that have a paddle switch activation only, may not provide an alarm if the belt just stops with coal on it.

If the Weigh Feeder Controller is not fed from UPS, a Vital Bus Circuit should be supplied to it.

Consider changing out the existing DC adjustable speed drive with 1980 vintage rectification equipment, with an AC Variable Frequency Drive with much better ride-through capability.

Survey equipment and bus operating voltages at various station and system loading conditions in order to determine that transformers so equipped, are set at taps conducive to providing better voltage during Voltage Sags.

Consider implementing a testing program that incorporates the use of a Voltage Sag Generator to identify equipment that may be susceptible to Voltage Sags.

5.5. Future Considerations

The most economical solutions are almost always associated with the individual components that make up a system. System alternatives provide less economical solutions.

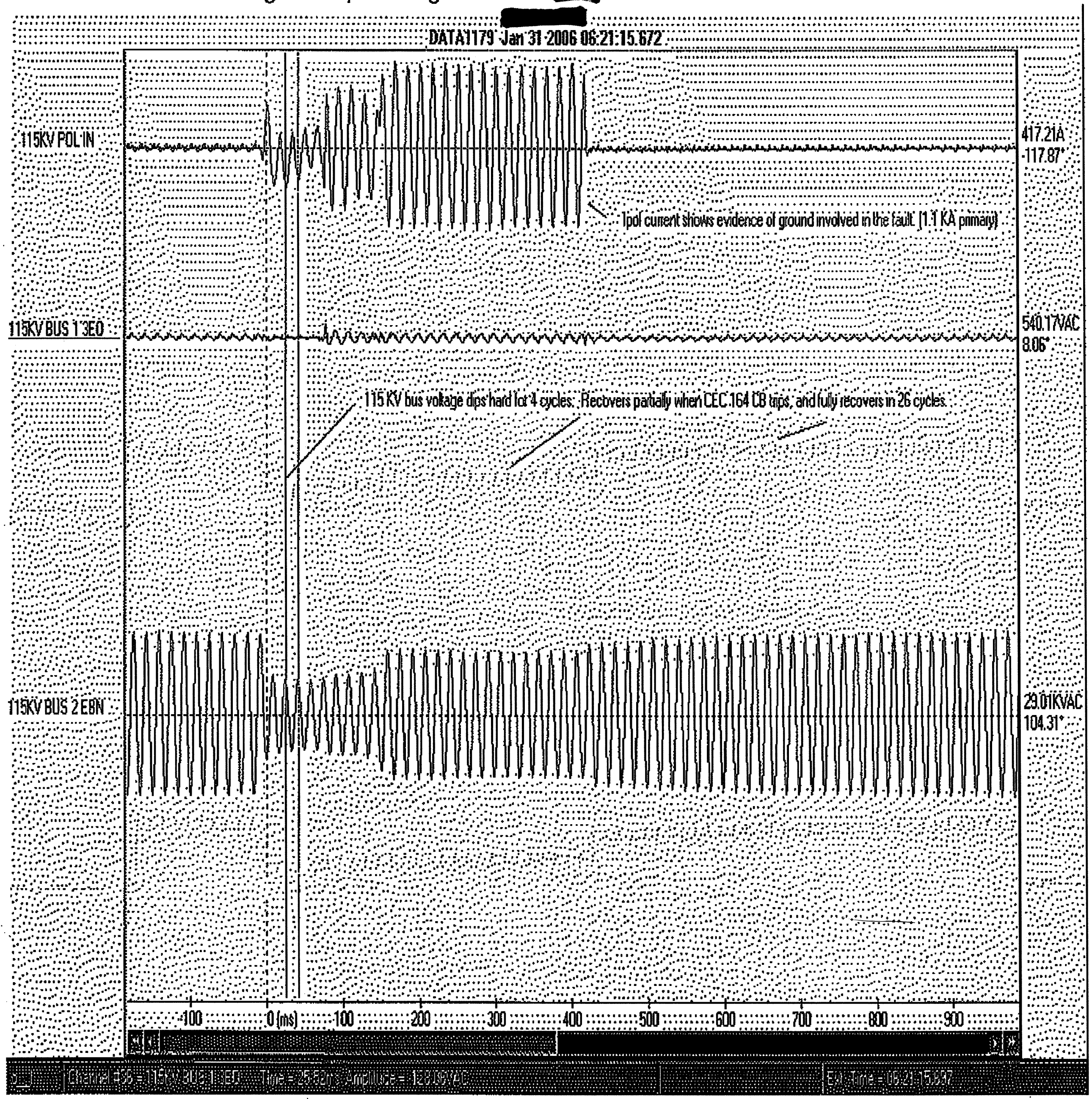
Identifying the weakest link in various critical systems will provide the most economical results.

System studies for obtaining the most beneficial Voltage profiles for the operating systems should be considered, and may not be cost prohibitive after the current efforts to construct accurate models of all of the stations is complete.

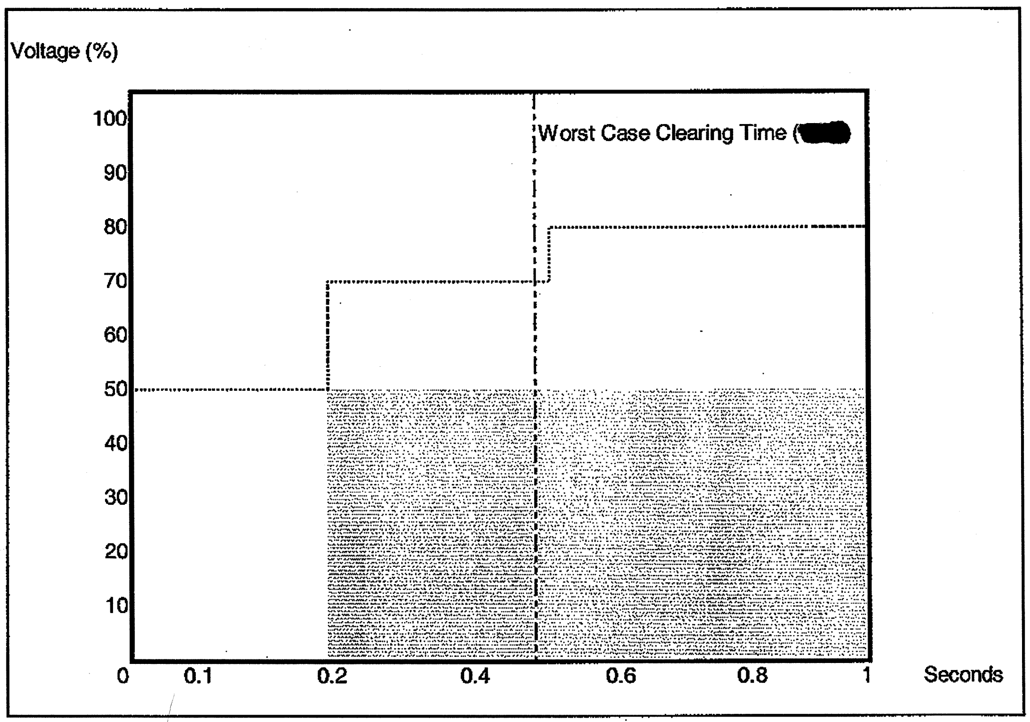
Future transmission considerations should include replacing old equipment if the age is associated with failures, particularly at the [redacted] Switchyard. These replacements could provide opportunities to further sectionalize the bus to provide better reliability if economically justifiable.

6. EXHIBIT 1 - FAULT RECORDER DATA FROM JANUARY 2006

Frame 9 - 115KV bus voltages and polarizing currents at [redacted]



11. EXHIBIT 6 – VOLTAGE SAG TOLERANCE CURVE FOR SEMICONDUCTOR INDUSTRY


Voltage (%)
100
90
80
70
60
50
40
30
20
10
0
0.1
0.2
0.4
0.6
0.8
1
Seconds
Worst Case Clearing Time ([redacted]

Generator Owner PRC-024 SERC Field Test Reporting Form

SC Generation and Transmission Submittal   Date: 6-07-2007

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

<u>Provide the following information:</u>

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? **2 Hours**
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☒ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic. **See Curve #2 of the first attachment.**
4. How many man-hours did it take to develop the methodology / tools? **2 Hours**
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic?   **<u>X</u>** Yes   No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? **2 Hours**
7. List any material costs associated with the generator frequency withstand capability portion of this field test. **Minimal**
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? **2 Hours**
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   Computerized coordination curves

   ☐ Manual coordination curves

   ☒ Combination (computerized / manual)

10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic. **For the first attempt, calculated the high side voltage required for the unit to absorb**

enough Mvars to operate the Back-up Over Current Relay (BUOC) via steady state evaluation with steady state Mvar limits relaxed. A small bus loadflow was created for dynamic simulations – with the test machine and a large dominant "Eastern Interconnection" machine with high inertia and constant excitation. Fault impedances were varied to approximate the LVRT characteristic in the Field Test guidelines at the highside of the GSU for the test machine. MVA was plotted from the test machine to see if the BUOC relay, set at 1.3 times unit MVA with a 70 cycle time delay, would pick up and time out. Other less severe faults within the LVRT characteristic were also assessed to ensure exciter dynamics, when presented with higher voltages at the exciter PPTs, would not result in operation of the aforementioned BUOC relay.

11. How many man-hours did it take to develop the methodology / tools? **N/A**
12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☐ Yes ☒ No **(No, per steady state simulations)**

    ☒ Yes No **(Yes, per dynamic simulations- see second attachment)**

    If no please attach additional information as appropriate. **See Curve #1 of first attachment.**
13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? **4.5 Hours (steady state) + 8.0 Hours (dynamics)**
14. List any material costs associated with the generator LVRT capability portion of this field test. **Minimal**
15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard. **Back-up Over Current setting can not be relaxed without compromising the generator protection. If units are identified where the BUOC is limiting, application of a very inverse time over-current relay and an impedance relay could <u>possibly</u> be set to provide adequate generation protection.**
16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

    See attached Curve #1 (Voltage) and Curve #2 (Frequency) of first attachment.
17. Name of the person completing the form:

    R.T. Wingard and Lee Taylor

    Phone Number **205-992-7167 and 205-257-7467**

    Company Name **Southern Company Services**

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

Generator Owner PRC-024 SERC Field Test Reporting Form

Scan001.PDF

Steady State Voltage and Frequency Coordination Curves- **first attachment.**

SouthernCoalUnit5_L
VRT.pdf

Dynamic Simulation Plots- **second attachment.**

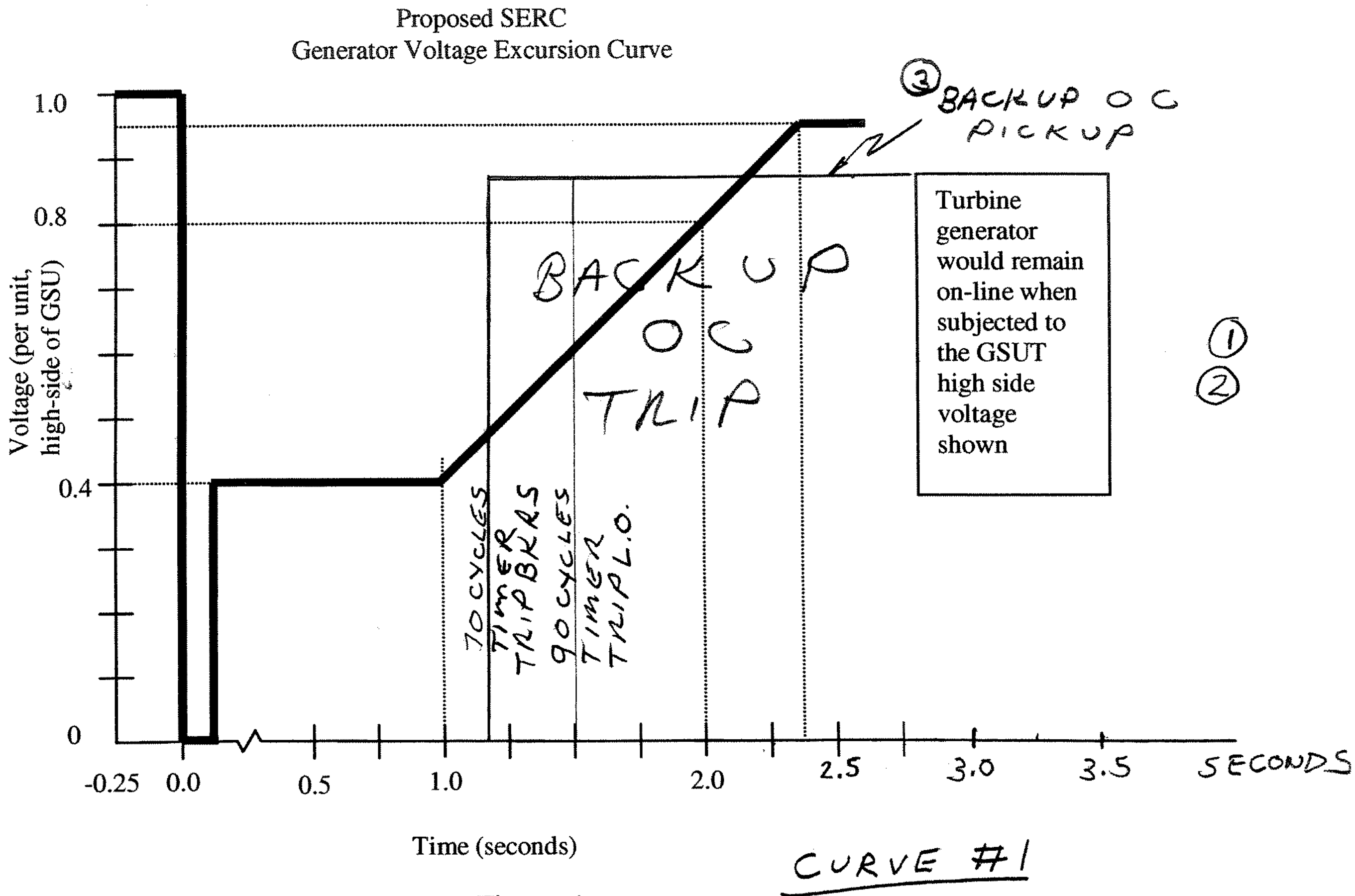


Figure 4

① BUS UV RELAYS ARE SET FROM 45 TO 60% WITH TIME DELAYS OVER 9 SECONDS.

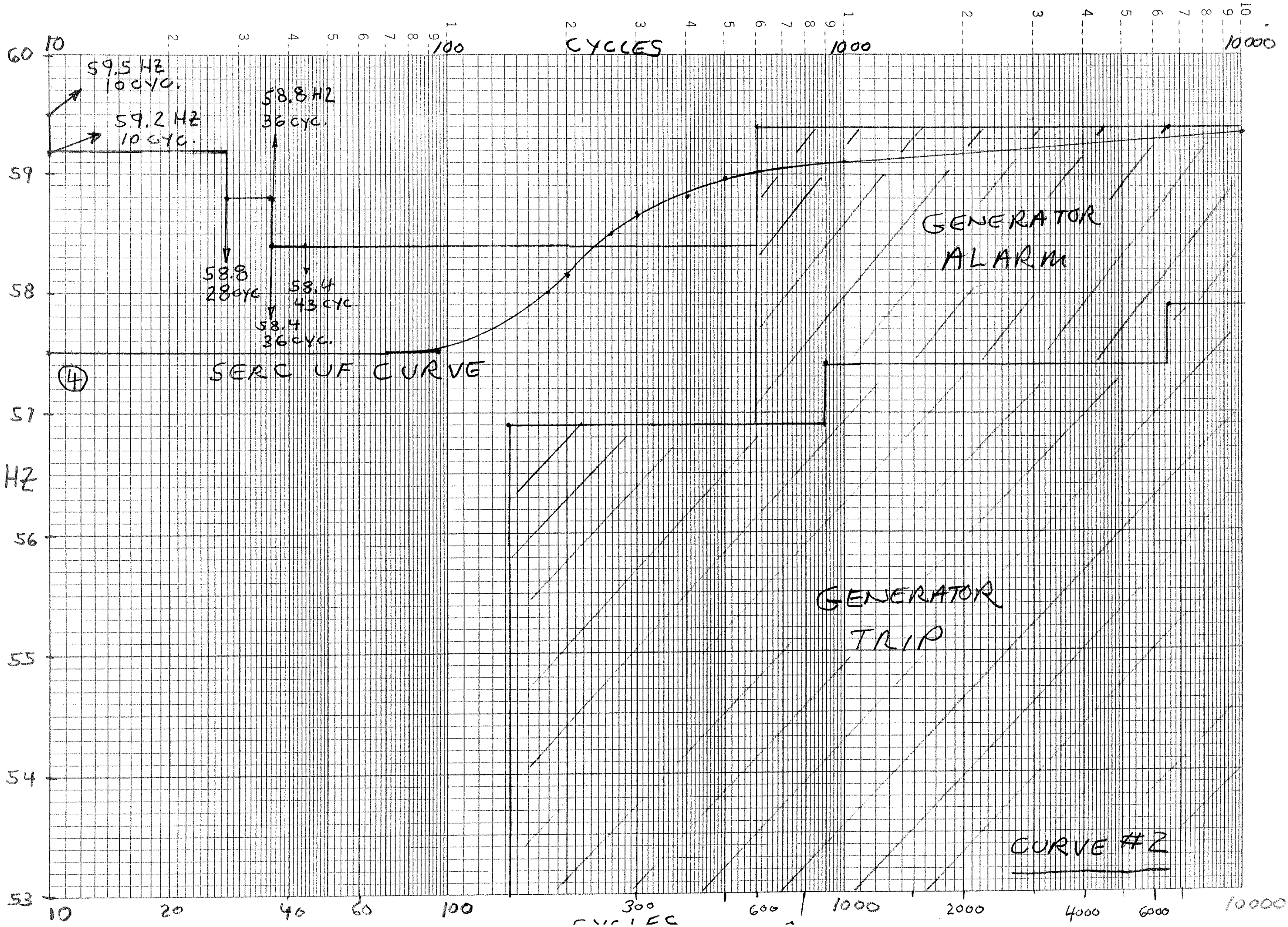
② LOSS OF EXCITATION RELAY WILL NOT OPERATE FOR MVARS OUT WHICH IS WHAT WOULD OCCUR WITH A LOW 230KV BUS VOLTAGE.

③ BACKUP O.C. WILL TRIP FOR THIS U.V. CURVE.

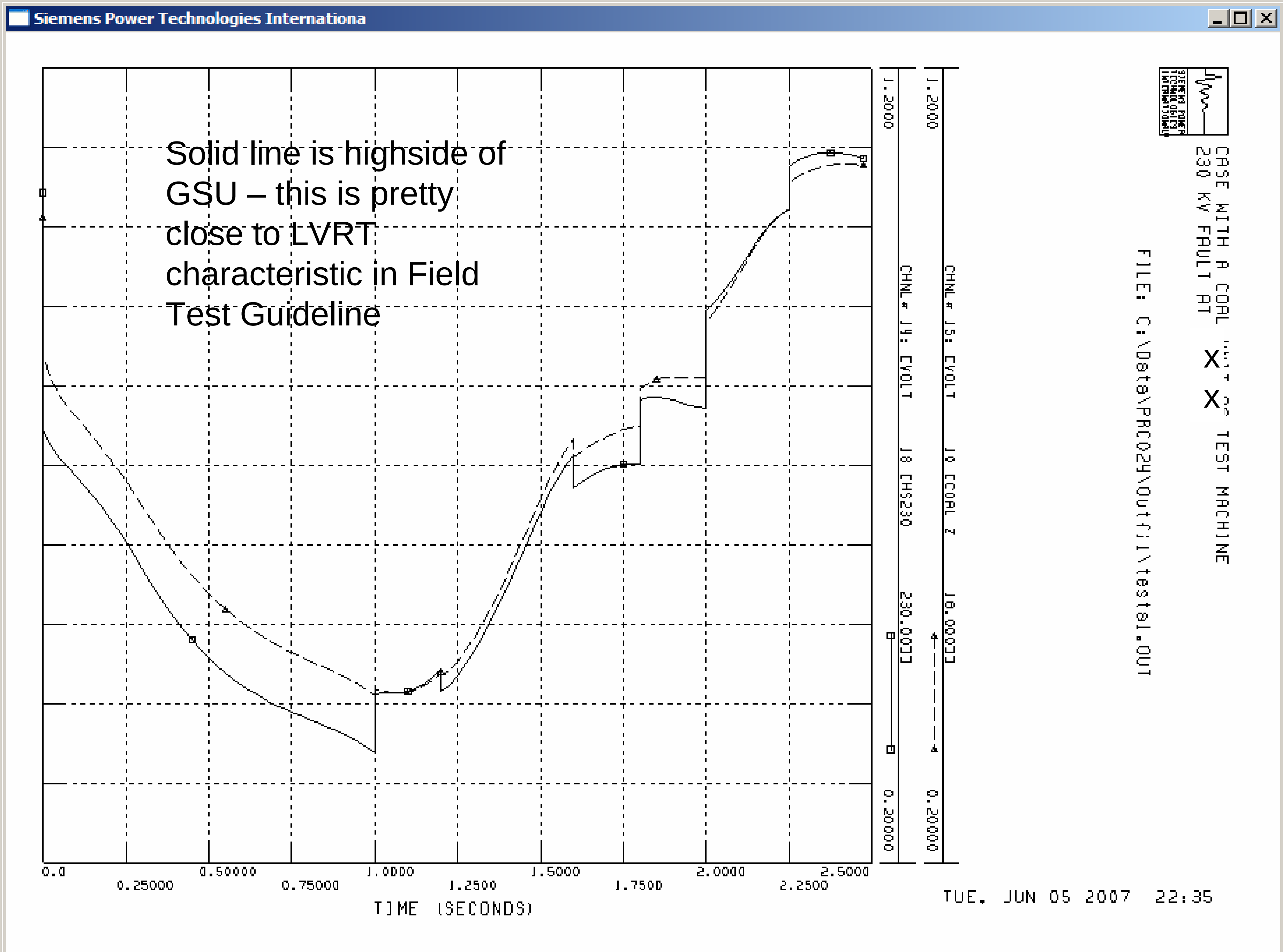
④ GENERATOR UF RELAYS COORDINATE WITH CURVE.

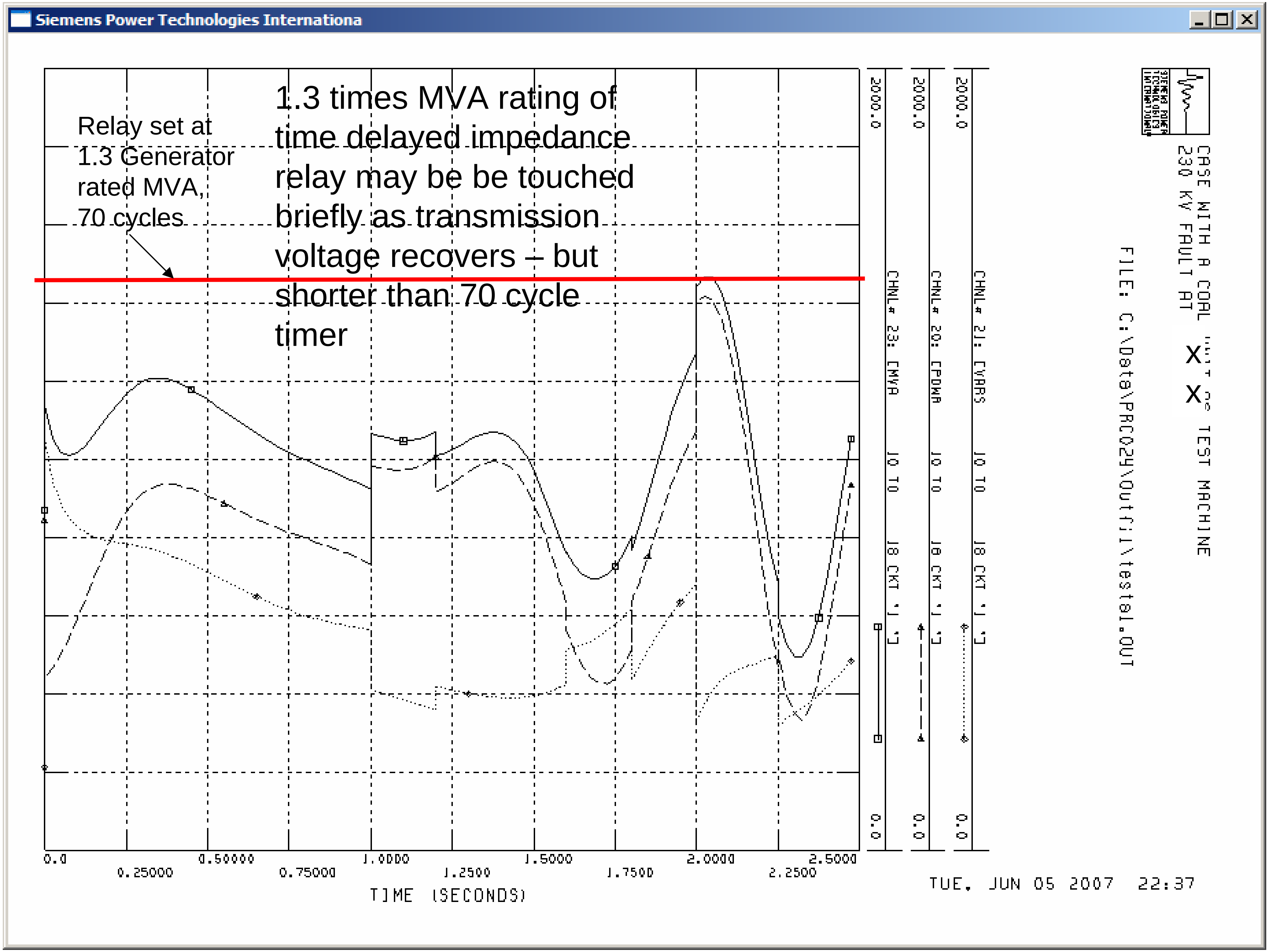
K+E SEMI-LOGARITHMIC • 3 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 5490

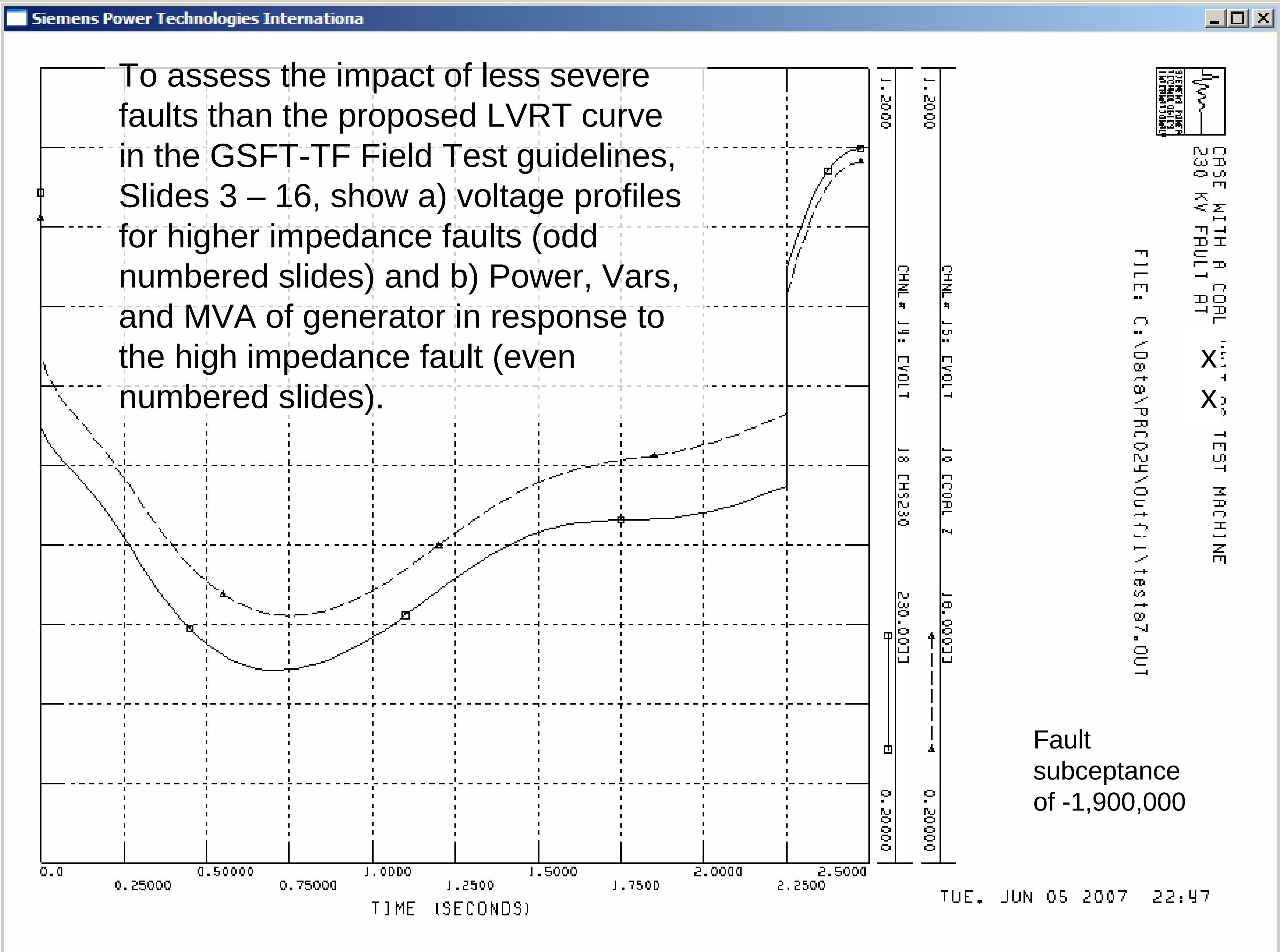


Solid line is highside of GSU – this is pretty close to LVRT characteristic in Field Test Guideline

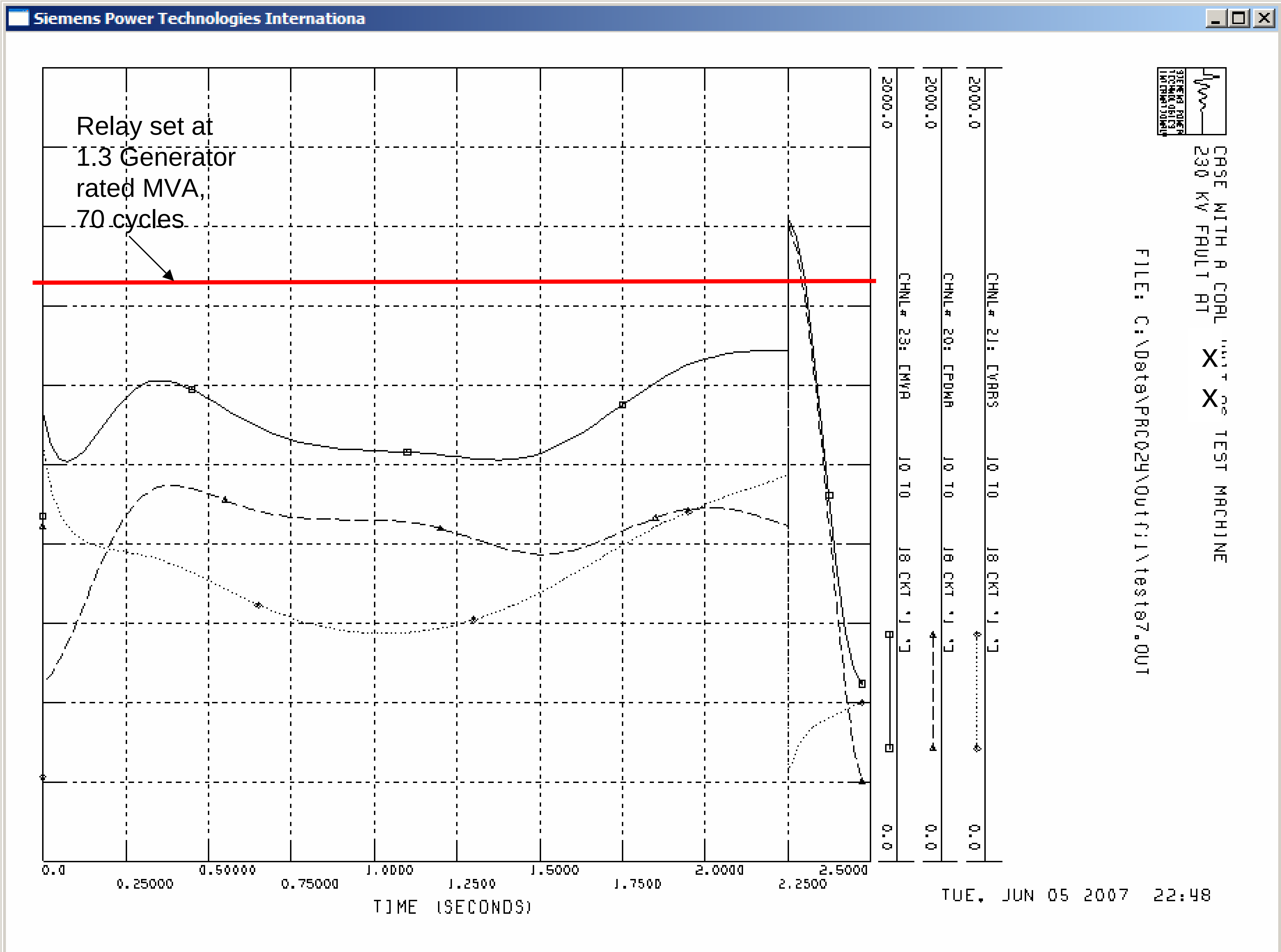


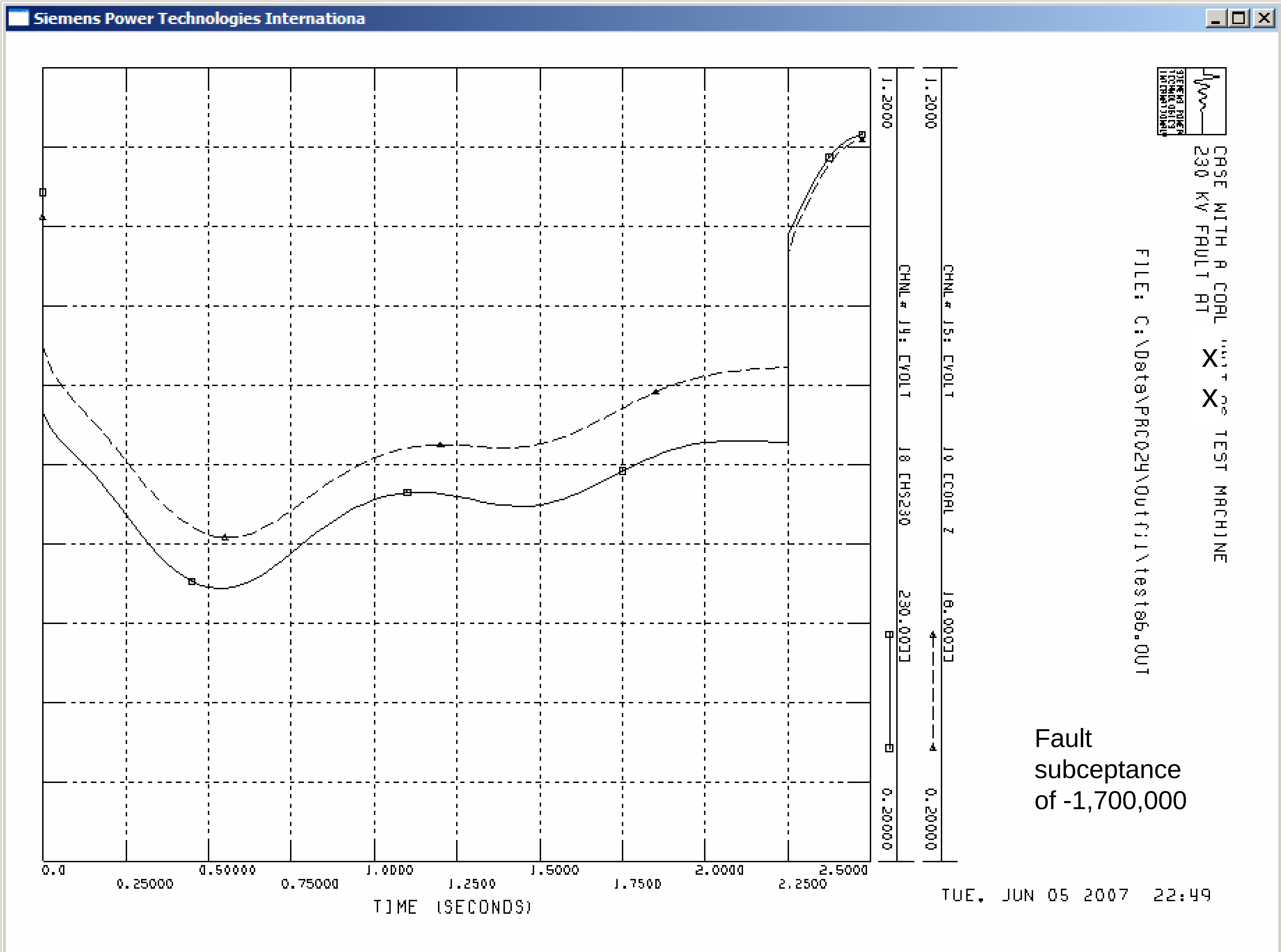

Siemens Power Technologies Internationa
Relay set at 1.3 Generator rated MVA, 70 cycles
1.3 times MVA rating of time delayed impedance relay may be be touched briefly as transmission voltage recovers – but shorter than 70 cycle timer
2000.0
0.0
CHNL# 23: CMVA 10 TO 18 CKT '1 '
CHNL# 20: CPOWR 10 TO 18 CKT '1 '
CHNL# 21: CVARS 10 TO 18 CKT '1 '
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
CASE WITH A COAL
230 KV FAULT AT
TEST MACHINE
X
X
TUE, JUN 05 2007 22:37

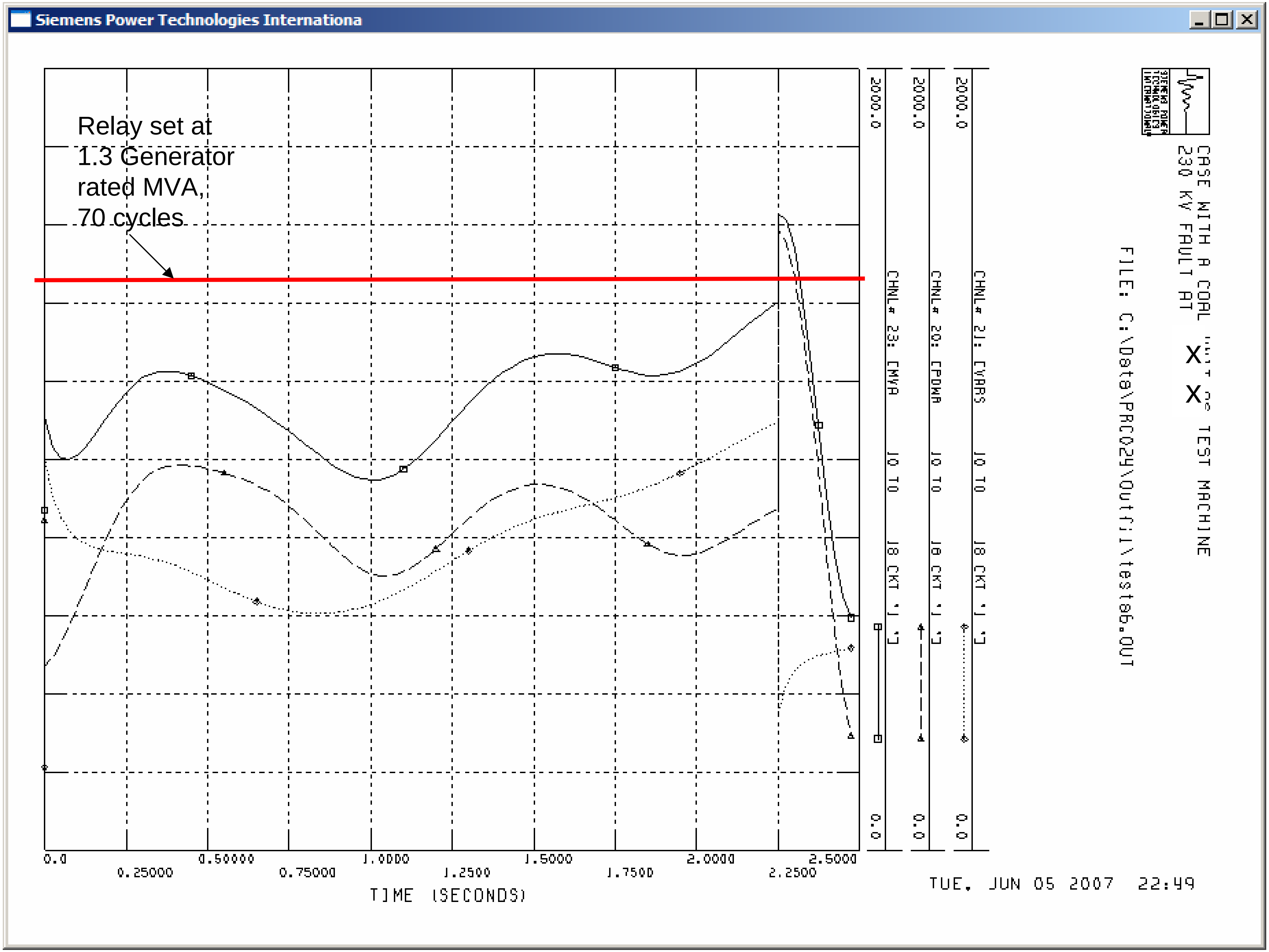
To assess the impact of less severe faults than the proposed LVRT curve in the GSFT-TF Field Test guidelines, Slides 3 – 16, show a) voltage profiles for higher impedance faults (odd numbered slides) and b) Power, Vars, and MVA of generator in response to the high impedance fault (even numbered slides).



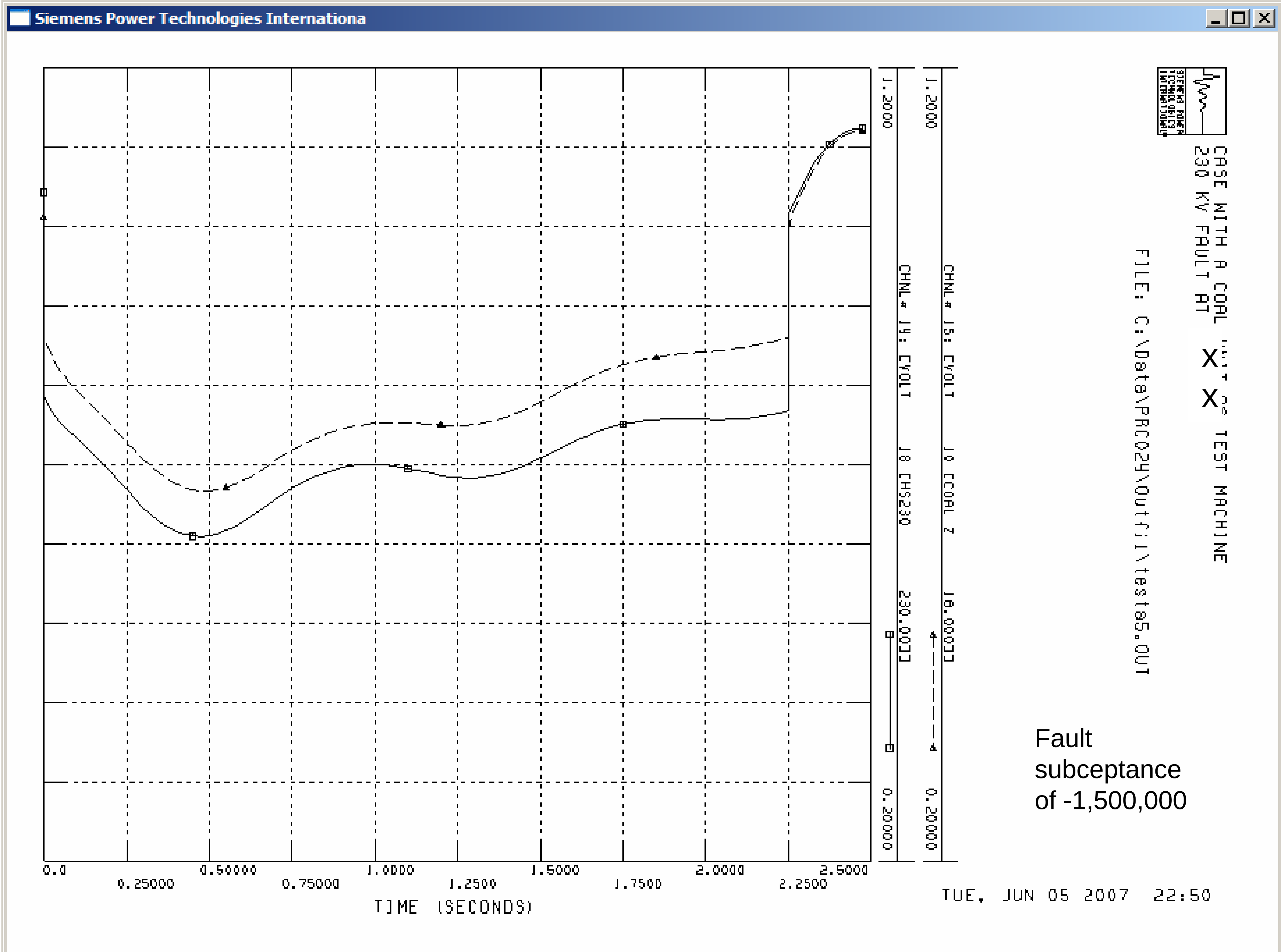
Fault subceptance of -1,900,000

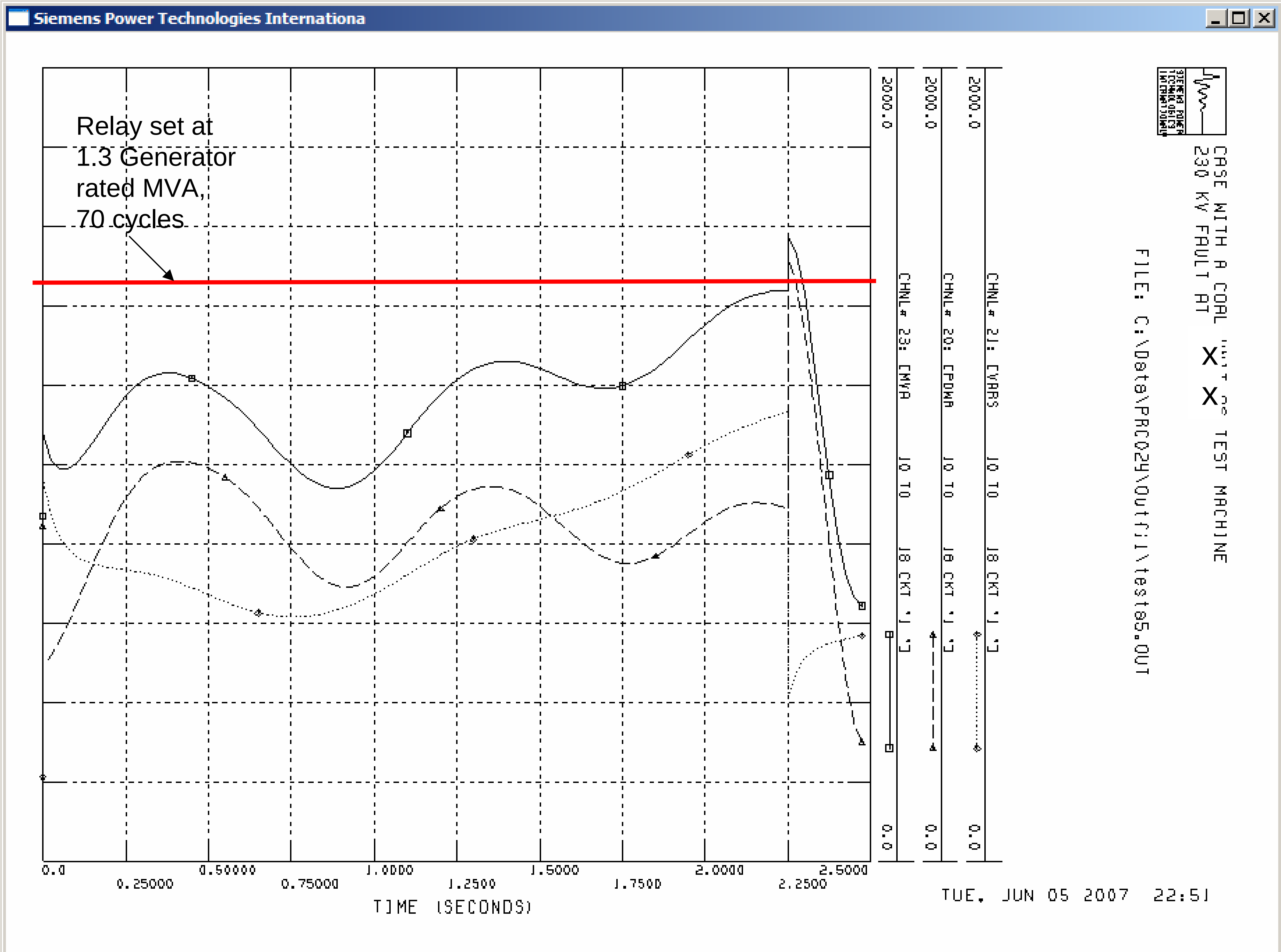

Siemens Power Technologies Internationa
Relay set at 1.3 Generator rated MVA, 70 cycles
2000.0
0.0
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
TUE, JUN 05 2007 22:48
CASE WITH A COAL
TEST MACHINE
230 KV FAULT AT
X
X


Siemens Power Technologies Internationa
TIME (SECONDS)
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
1.2000
0.20000
CHNL# 14: [VOLT 18 [HS230 230.00]]
CHNL# 15: [VOLT 10 [COAL 2 18.000]]
CASE WITH A COAL TEST MACHINE
230 KV FAULT AT
FILE: C:\Data\PRC024\Outfil\test6.OUT
TUE, JUN 05 2007 22:49
Fault
subceptance
of -1,700,000

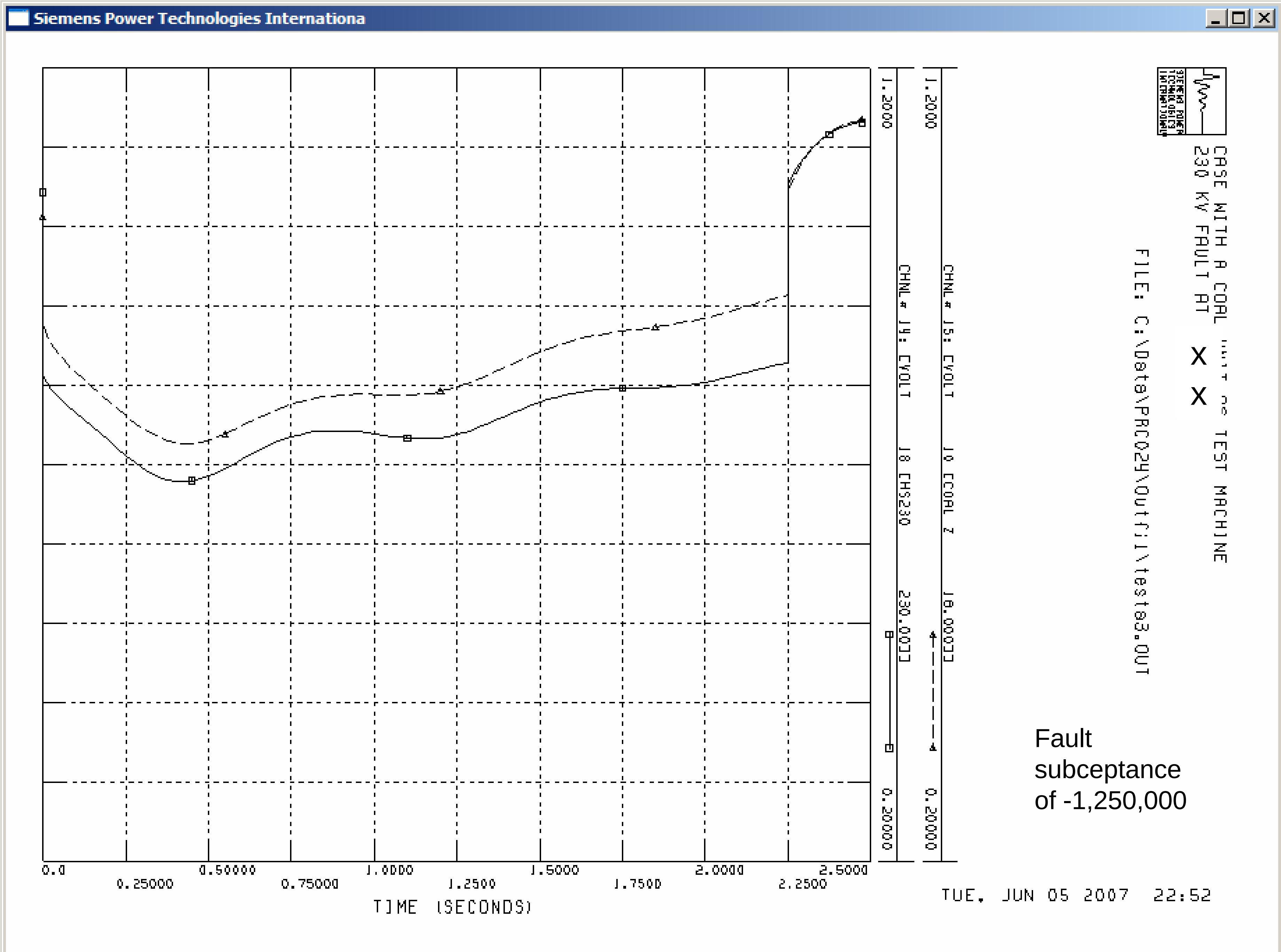


Siemens Power Technologies Internationa
Relay set at 1.3 Generator rated MVA, 70 cycles
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
2000.0
0.0
CHNL# 23: [MVA 10 TO 18 CKT '1 ']
CHNL# 20: [POWR 10 TO 18 CKT '1 ']
CHNL# 21: [VARS 10 TO 18 CKT '1 ']
FILE: C:\Data\PRC024\Outfiil\test6b.OUT
CASE WITH A COAL UNIT AS TEST MACHINE
230 KV FAULT AT
TUE, JUN 05 2007 22:49

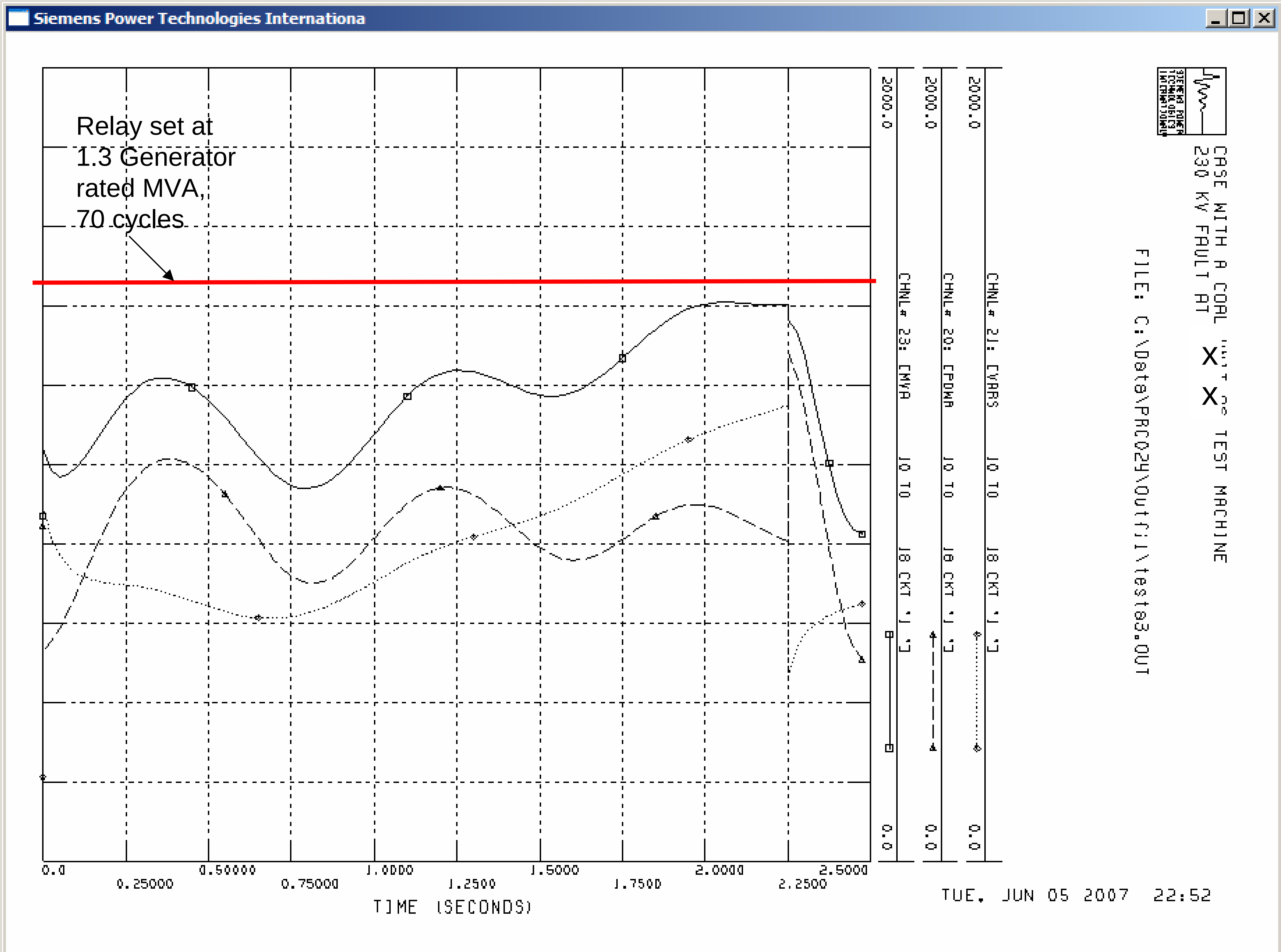

Siemens Power Technologies Internationa
TIME (SECONDS)
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
1.2000
0.20000
CHNL# 14: [VOLT 18 [HS230 230.00]]
CHNL# 15: [VOLT 18 [COAL Z 18.000]]
CASE WITH A COAL
230 KV FAULT AT
TEST MACHINE
FILE: C:\Data\PRC024\Outfil\test85.OUT
TUE, JUN 05 2007 22:50
Fault subceptance of -1,500,000

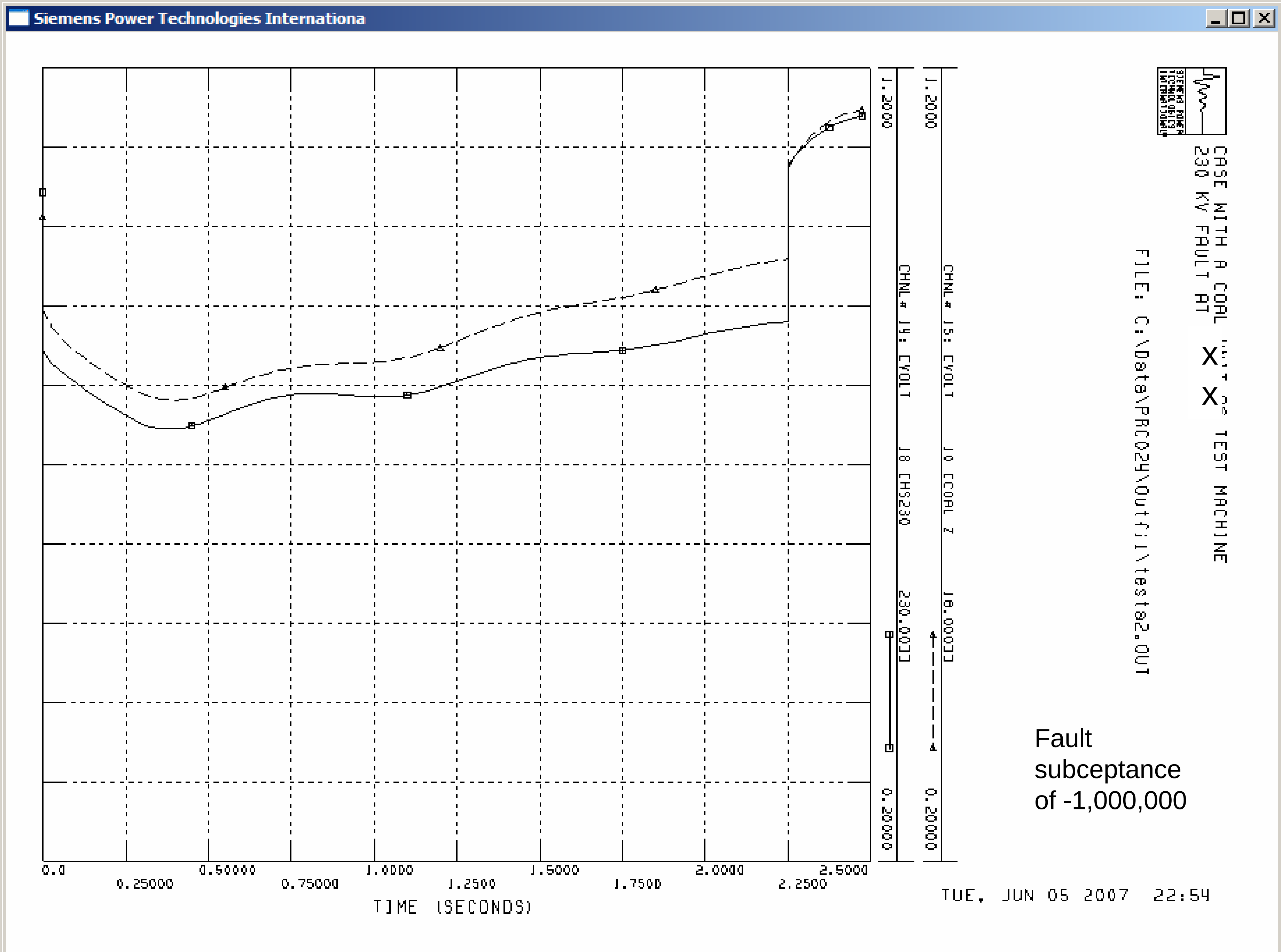


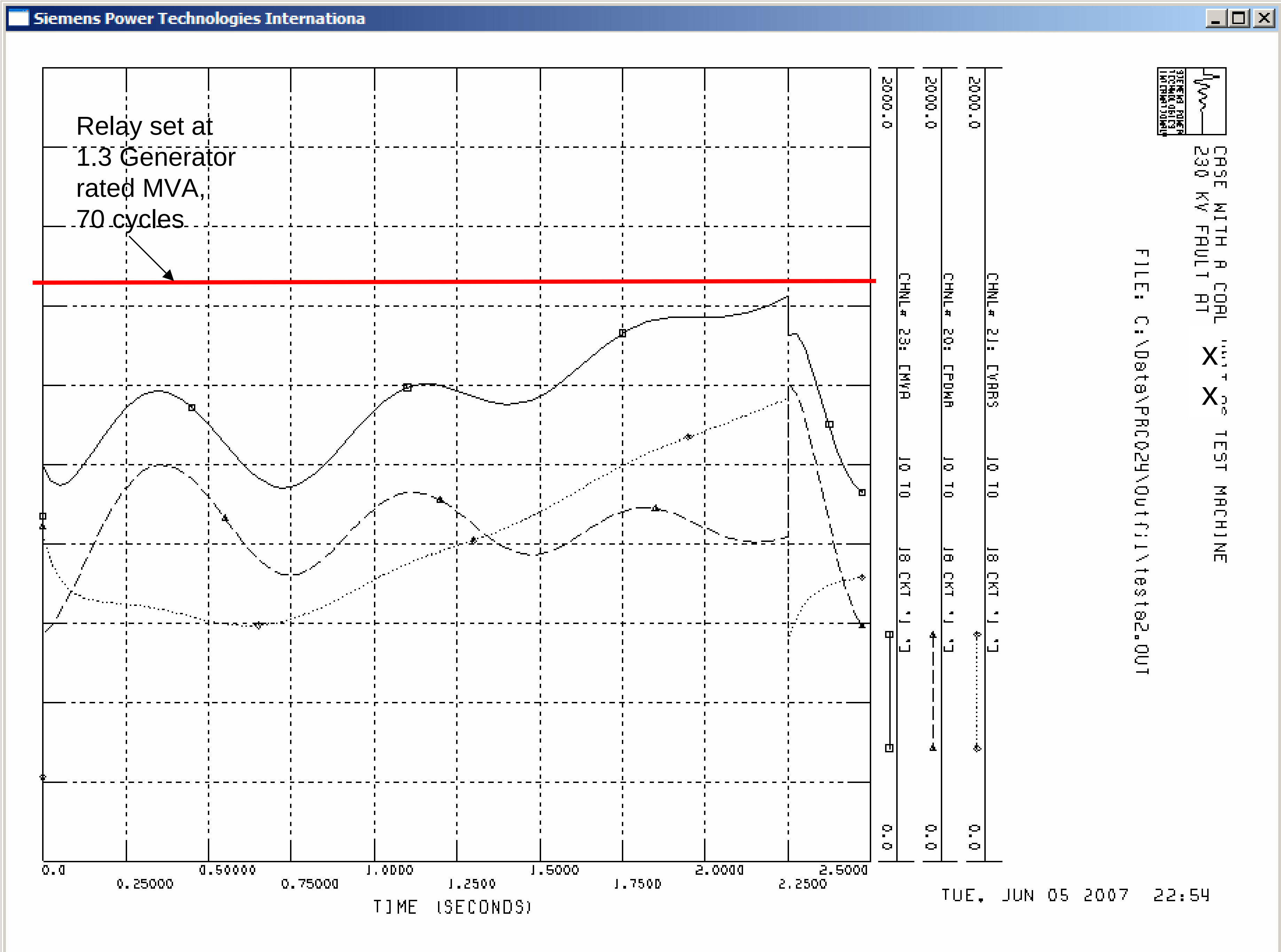
Siemens Power Technologies Internationa
Relay set at 1.3 Generator rated MVA, 70 cycles
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
2000.0
0.0
CHNL# 23: [MVA
CHNL# 20: [PGWA
CHNL# 21: [VARS
CASE WITH A COAL
230 KV FAULT AT
TEST MACHINE
FILE: C:\Data\PRC024\Outfiles\test85.OUT
TUE, JUN 05 2007 22:51



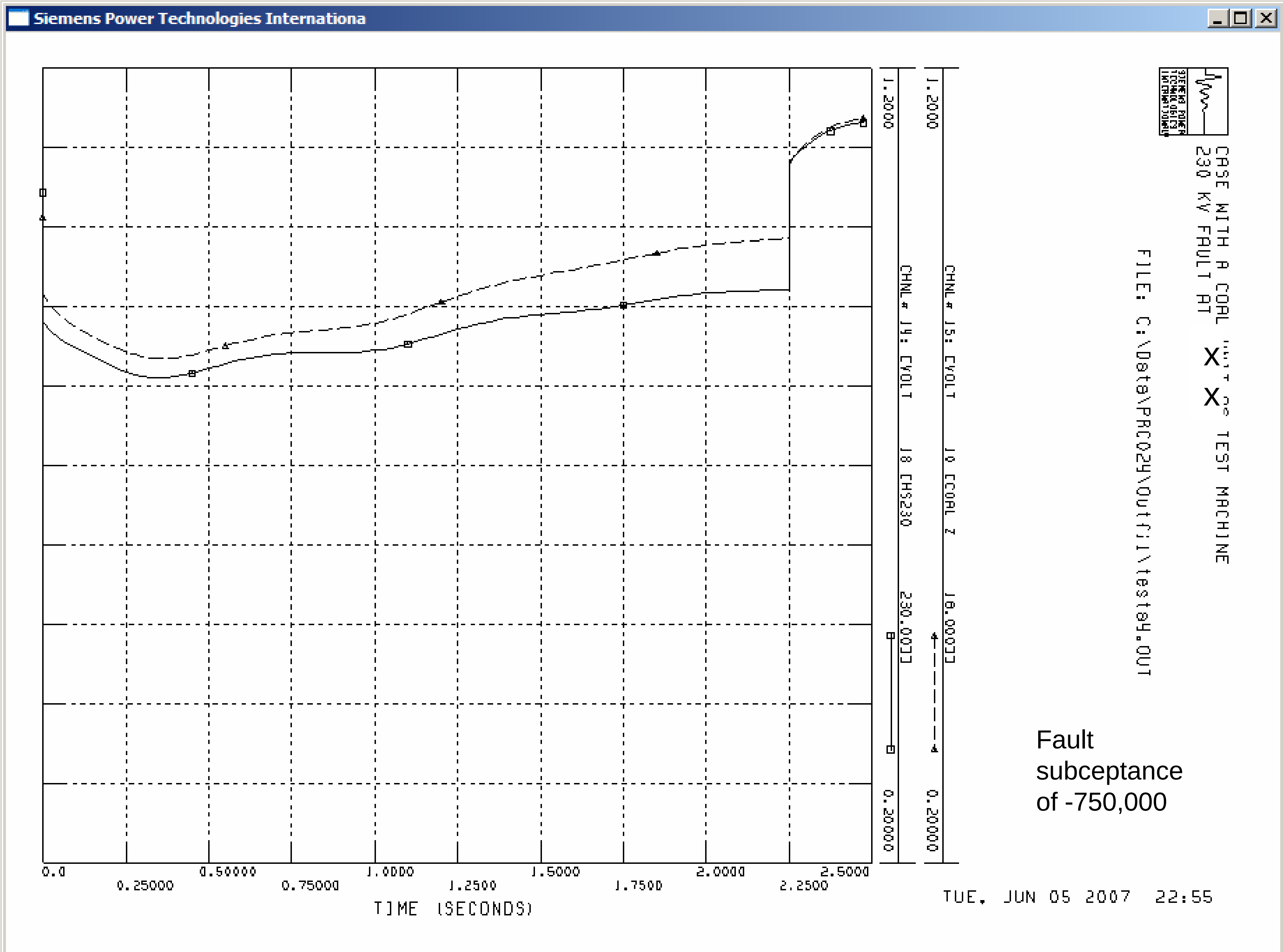
Fault subceptance of -1,250,000


Siemens Power Technologies Internationa
Relay set at 1.3 Generator rated MVA, 70 cycles
2000.0
0.0
CHNL# 23: [MVA
CHNL# 20: [POWR
CHNL# 21: [VARS
CASE WITH A COAL
230 KV FAULT AT
TEST MACHINE
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
TUE, JUN 05 2007 22:52

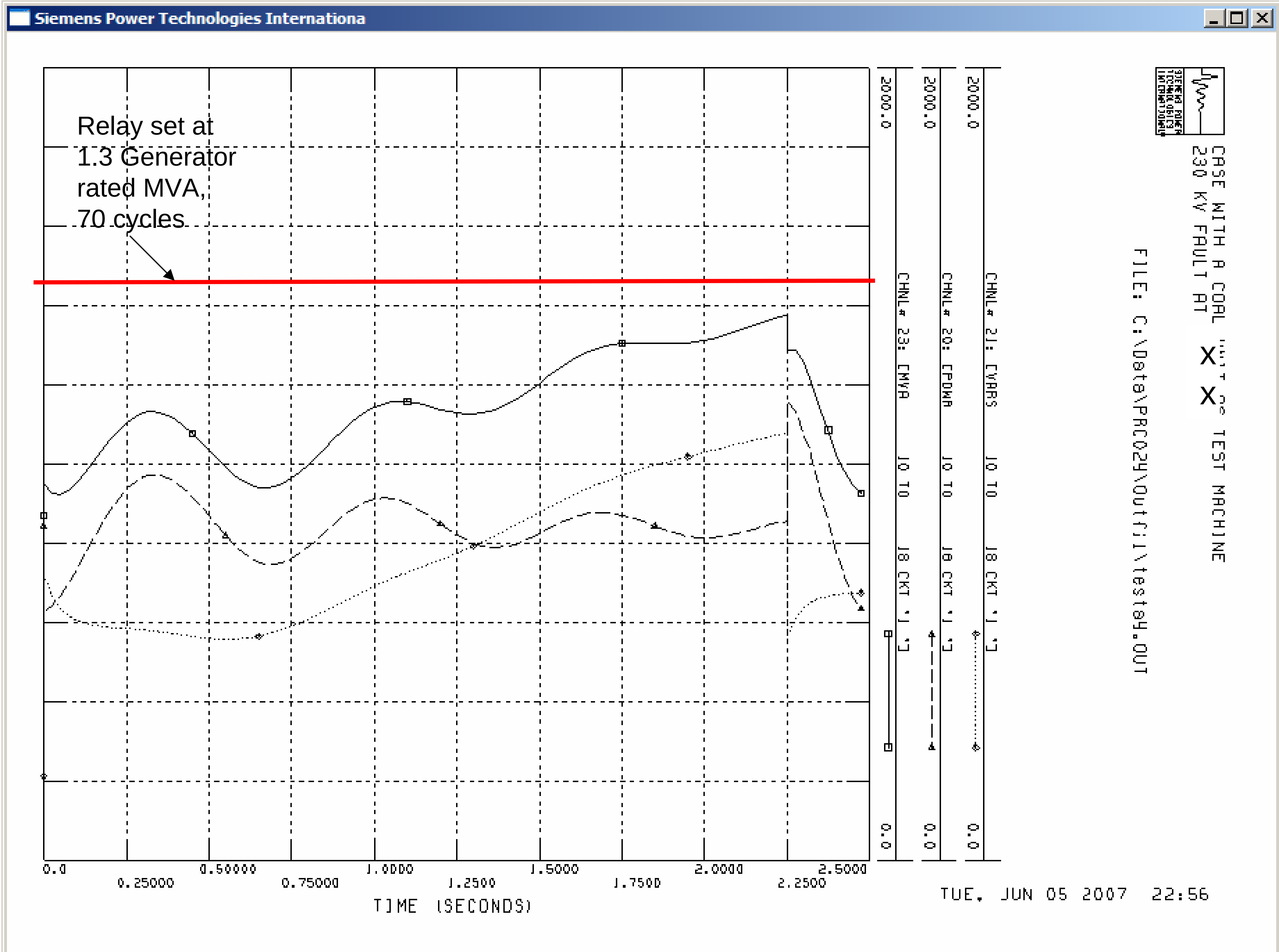

Siemens Power Technologies Internationa
1.2000
0.20000
CHNL# 14: [VOLT
CHNL# 15: [VOLT
CASE WITH A COAL
TEST MACHINE
230 KV FAULT AT
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
TUE, JUN 05 2007 22:54
Fault subceptance of -1,000,000

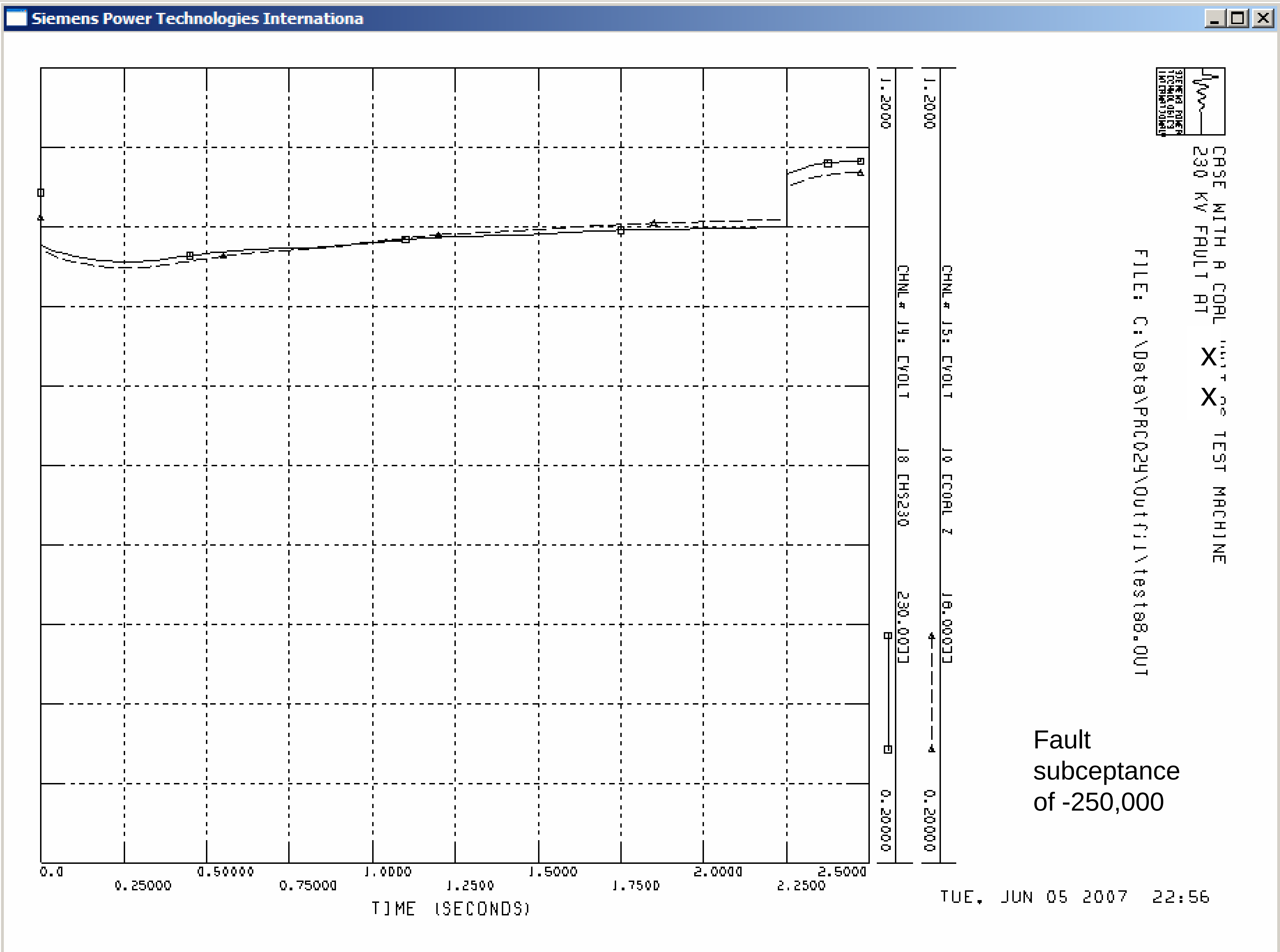


Siemens Power Technologies Internationa
Relay set at
1.3 Generator
rated MVA,
70 cycles
2000.0
0.0
CHNL# 23: [MVA
CHNL# 20: [POWR
CHNL# 21: [VARS
CASE WITH A COAL
230 KV FAULT AT
TEST MACHINE
TIME (SECONDS)
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TUE, JUN 05 2007 22:54

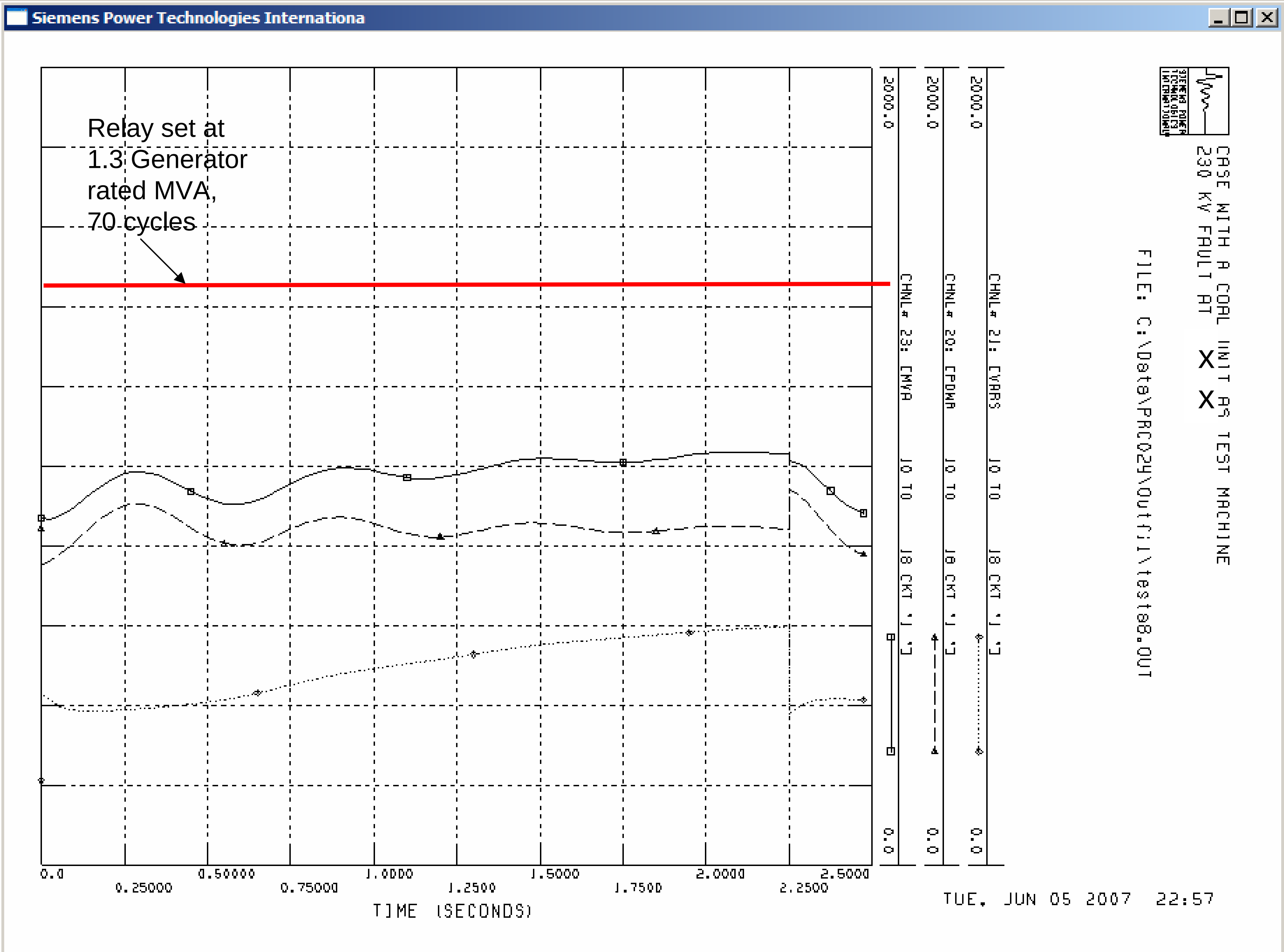


Fault
subceptance
of -750,000


Siemens Power Technologies Internationa
Relay set at
1.3 Generator
rated MVA,
70 cycles
2000.0
0.0
CHNL# 23: [MVA
CHNL# 20: [PDWR
CHNL# 21: [VARS
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
TUE, JUN 05 2007 22:56
230 KV FAULT AT
TEST MACHINE



Siemens Power Technologies Internationa
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
1.2000
0.20000
CHNL# 14: [VOLT 18 [HS230 230.00]]
1.2000
0.20000
CHNL# 15: [VOLT 10 [COAL Z 18.000]]
CASE WITH A COAL
TEST MACHINE
230 KV FAULT AT
FILE: C:\Data\PRC024\Outfil\test8.OUT
TUE, JUN 05 2007 22:56
Fault subceptance of -250,000



Siemens Power Technologies Internationa
Relay set at
1.3 Generator
rated MVA,
70 cycles
2000.0
0.0
CHNL# 23: [MVA 10 TO 18 CKT '1 ']
CHNL# 20: [POWR 10 TO 18 CKT '1 ']
CHNL# 21: [VARS 10 TO 18 CKT '1 ']
CASE WITH A COAL UNIT AS TEST MACHINE
230 KV FAULT AT
X
X
FILE: C:\Data\PRC024\Outfil\test8.OUT
0.0
0.25000
0.50000
0.75000
1.0000
1.2500
1.5000
1.7500
2.0000
2.2500
2.5000
TIME (SECONDS)
TUE, JUN 05 2007 22:57

Comments Related to Balance of Plant Performance for SERC Proposed Frequency and Voltage Ride thru Curves
Rev. 0
Date: 6/11/2007

The proposed Under Frequency (UF) and Under Voltage (UV) requirements in "SERC Field Test Guidelines- Generator Performance during Frequency and Voltage Excursions" developed from the draft version of NERC Standard PRC-024 have been under review by power plant design engineers to access the impact on plant continuous performance. Due to the complexity of todays power generating stations this review is incomplete. However, the following does address a significant portion of the components and systems that can be impacted by the proposed UF and UV ride thru curves contained in the SERC document.

A. Under Frequency Ride Through Curves (Figure 1 of SERC Field Test Guidelines):

The ability of a unit/plant to ride through the proposed Under Frequency requirements depends on the under frequency response characteristics of the following equipment, systems and protective devices.

Note, in evaluating the effects of UF we assumed that in general the voltage also decreases in a similar manner as the frequency and thus the V/Hz does not increase significantly.

1. <u>Turbine Generators:</u> The primary units of concern are the turbo-generators and Combustion Turbines (CTs). Turbo-generators have under frequency limits established by the manufacturers due to turbine blade vibration (resonance) limitations. For most turbo-generating units, the subject limits are fairly well defined and typically are used to establish turbine under frequency protective and Under Frequency Load Shedding (UFLS) relay set-points. Based on the technical reviews to date, turbo-generator under frequency limitations are not expected to be a problem with the proposed curve and should coordinate.

Similar data on CTs needs to be developed but no published under frequency limits have been found. Finally, conventional hydro turbine-generators don't have under frequency limitations.

2. <u>Boiler Control Systems:</u> The comments on Boiler Control Systems (BCS) are primarily relating to the under voltage effects, however the issues are related. Most of the newer BCS's utilize UPS's which should minimize concerns with UF events. However, without reviewing the complete system, it cannot be confirmed that the BCS remote devices (instrument sending units and actuators) are

powered from dc or UPS supplies. On older plant designs, the BCS is typically fed from redundant ac sources (non UPS). Since both sources will see the same level of UF, one cannot generalize its performance during the UF event. Thus, this will require further study.

3. Nuclear Power Plants: The following relates to Pressurized Water Reactor (PWR) designs that utilize Reactor Coolant Pumps (RCPs). A critical part of the reactor protection system is to maintain flow through the reactor and the steam generators. This is accomplished with the RCPs. This is so critical that the subject pumps are equipped with flywheels to insure they will continue to turn for a specific period of time without ac power to the motors. The subject motors have under-frequency protection that will trip the ac supply breakers to the motors if the frequency drops (low frequency results in a slow down of the motor and thus the pump) below a specified set-point. A review of at least two PWR plants shows the proposed UF limit curve coordinates with the UF ride-thru curve. It is recommended that other PWR owner/operators review these set points to insure proper coordination.

Please note that Boiling Water Reactor (BWR) plants and systems were not reviewed and it is recommended that a detailed review be performed.

Another unique sub-system employed in Nuclear Power Plants that should be reviewed is the Emergency Diesel Generator (EDG). Each EDG typically has under frequency relays that protect it if a severe UF event occurs while the EDG is paralleled with the system for testing. A review of one plant showed the EDG UF relays to be set to trip in 20 cycles at 59.5 Hz. Thus, the EDG would likely trip for a severe UF event. However, this should not cause a unit trip or have any other adverse impact to the plant and, therefore, does not represent a coordination issue with the proposed UF requirements. Other Nuclear Plant owners/operators should review the EDG systems and the associated UF set points to ensure no adverse impacts are discovered.

Finally, it is recommended that the Reactor Trip System M-G Sets for a PWR nuclear unit be evaluated to determine if they could ride through the proposed under frequency excursion curve and maintain adequate power to the nuclear reactor rod controls. Time did not permit this review to be complete but if they are unable to ride thru, a reactor trip and, hence, unit trip will occur.

4. Generating Plant Protection Systems: A review of the protective relaying schemes applied at several generating stations was performed for the proposed UF curve. Of the units reviewed only one UF protection coordination problem was discovered. The subject coordination problem could be corrected to resolve the mis-coordination. Thus, the initial assessment is that the proposed UF requirements can be coordinated with plant protection.

Note: The above assumes the plant/system voltage will also decrease in a similar manner to the frequency. Otherwise, Volts per Hertz protection will need to be considered.

5. Station Service Loads: For station service loads, only induction motors and Adjustable Speed Drives (ASDs) were considered. In the case of an induction motor, the industry standards permit deviations of +/- 5% frequency deviation provided the voltage remains at rated. This operating limit is generally a continuous capability and would not apply for the short time period under consideration. If the frequency drops, the motor speed would be expected to drop in proportion to the frequency drop. Since the frequency drop is less than 5% motor loads are not expected to exhibit any significant short time performance problems.

For ASDs, more research is needed but, it is believed that they are also required to meet the +/- 5% deviation in rated frequency.

B. Under Voltage Ride Through (Figure 4 of SERC Field Test Guidelines):

1. Turbine-Generators: No specific short-time under voltage limits have been identified for turbine generators. On newer units or retrofit application that utilized static excitation systems powered from the generator or plant bus voltage, the proposed voltage transient would result in a reduction in excitation during the fault and voltage recovery period. Typically static systems are purchased with a minimum of 1.5 per unit ceiling voltage which means these systems would provide full excitation for generator bus voltages down to 75 % of rated. At voltages below this level, the excitation voltage would decrease during the fault profile given in the supplement. Calculations have been performed of expected generator and station service bus voltage for a sample plant which shows the generator bus voltage drops to approximately 30% for the switchyard fault (see Attachment A.) This would result in a maximum excitation voltage of 45% during the initial fault. Please note, even though the field voltage decreases almost instantaneously, the field current {terminal voltage producer} will take longer to decay from pre-fault levels.

Assessing the overall impact of the voltage profile further, would require dynamic studies of the unit/plant for the proposed transmission voltage profile.

2. Boiler Control Systems: The severity of the voltage transient and the resulting plant ac distribution system voltages would significantly impact the BCS even if it is powered from a UPS. The assessment to date indicates that some BCSs might require configuration changes and/or power supply changes to improve the possibility of survival of the subject event. As discussed above for UF events, each owner would need to evaluate the survivability of the BCS, actuators, transmitters, etc. for the stated voltage profile.

3. Station Service Loads: In general the station service loads are either unit connected (fed from transformers connected to the generator terminals) or fed from transformers supplied by the plant switchyard. Some plants designs have loads served from both sources (generator and switchyard) during normal operation. Examples of plants with some or all of station service loads normally supplied from the switchyard are nuclear power plants, many Combined Cycle plants, and plants with new scrubber loads.

To judge the overall impact of the proposed voltage ride through curve, two different plant distribution systems were modeled. A unit where all of the station service load is directly served from the generator was modeled first. The attachment titled "Typical Fossil Unit" (Attachment A) shows the generator bus voltage drops to approximately 30% for a high side fault. The corresponding station service bus voltages are also in the 30% range. It is judged that most of the station service load should ride thru the initial fault event of 15 cycles, but the performance and ride thru capability for the recovery phase of the proposed voltage profile curve cannot be predicted. A dynamic simulation would be required to determine if the station service loads would fully recover. This phase of the analysis was not completed.

Another issue identified for PWR Nuclear power units is the RCP under voltage protection. These under voltage relays are designed to trip the unit by tripping the rod control system in the event of a loss of voltage to the RCPs. A typical trip setting for these relays is less than 67% of the rated bus voltage (4160V) for 0.5 seconds. These relays would likely trip for the proposed voltage excursion curve, thus tripping these unit(s).

The second distribution system modeled is for a typical CC plant where all or a portion of the station service load is supplied from the switchyard. This arrangement also applies to the emergency buses for most Nuclear Power Plants. The results of this analysis are provided in Attachment B. For a high side fault the station service bus voltage drops to zero as one would expect. Again, it is expected that most of the loads would remain connected to the supply buses during the initial fault (approximately 15 cycles), but the long term response which would occur during the voltage recovery phase can not be assessed without dynamically modeling the system.

A special case for this configuration is the emergency buses for Nuclear Power Plants. For these buses, special protective relaying schemes are employed to detect loss of off-site voltage. If these relays operate, the buses are isolated from the transmission system, the EDGs will start and safety related loads are sequenced onto the isolated sources. This action is highly undesirable but within the design basis of the plant. If this event occurred it would be very unlikely that either type of unit (Nuclear or CC unit) would remain connected to the grid. In fact, for the two nuclear plants reviewed, it was determined that the proposed voltage excursion curve would cause the loss-of-offsite-power (LOSP/LOOP) relays to actuate and trip the unit. Due to the very short time delays employed for nuclear plant LOSP/LOOP protection, it is believe that these relays would operate for most Nuclear units for the proposed curve. However, it is recommended that each nuclear unit be evaluated to determine if the proposed voltage ride thru would actuate the LOSP/LOOP relays and automatically trip the unit.

The final configuration to consider is where new scrubber systems are being installed and the station service load for the scrubber is fed from the switchyard. This configuration is also representative of the system shown in Attachment B. The consequence of momentary loss of supply voltage and slow voltage recovery time has not been fully evaluated. However, on some designs, initial reviews indicates that these units may survive the proposed voltage transient (lose the scrubber but not the unit.)

4. Generating Plant Protection Systems: Relay engineers have done a review of typical protection schemes utilized on most generating units in regard to protection responses to the voltage profile. The following addresses typical generator and station service protection. Special protective schemes for nuclear power stations (degraded grid, LOSP, Reactor Protection Systems) are not included except as noted above. The following relays are highlighted:

a. Generator Under voltage Relays: There are some units equipped with relays which trip for under voltage on the generator bus. Assuming the generator bus voltage follows the high-side transmission voltage exactly, there are a couple of these relays that were found to be marginal. However, since the generator voltage does not drop to zero for a transmission high side fault and the regulator will be attempting to boost the generator voltage back normal, the voltage seen by the relays should be less severe than a total loss of voltage the relays probably will not operate. A detailed model of the generator and exciter/voltage regulator would be required to determine the exact response of the relays to give a more definitive answer.

b. Power Potential Source Exciter PPT Secondary Relaying: Several units reviewed have under voltage relays connected on the low side of the exciter Power Potential Transformer (PPT) secondary which are intended to operate for close in faults if the excitation should collapse. The intended setting for these relays is 2 seconds at zero volts. Dynamic simulations show that the exciter would be expected to sustain itself for a fault on the transmission system since its voltage will not drop to zero.

c. Station Service Bus Under Voltage Relays: Some units have bus under voltage relays that trip motor loads for cases of extended under voltage. For the cases reviewed the time delay was found to be much longer than the UV excursion lasted.

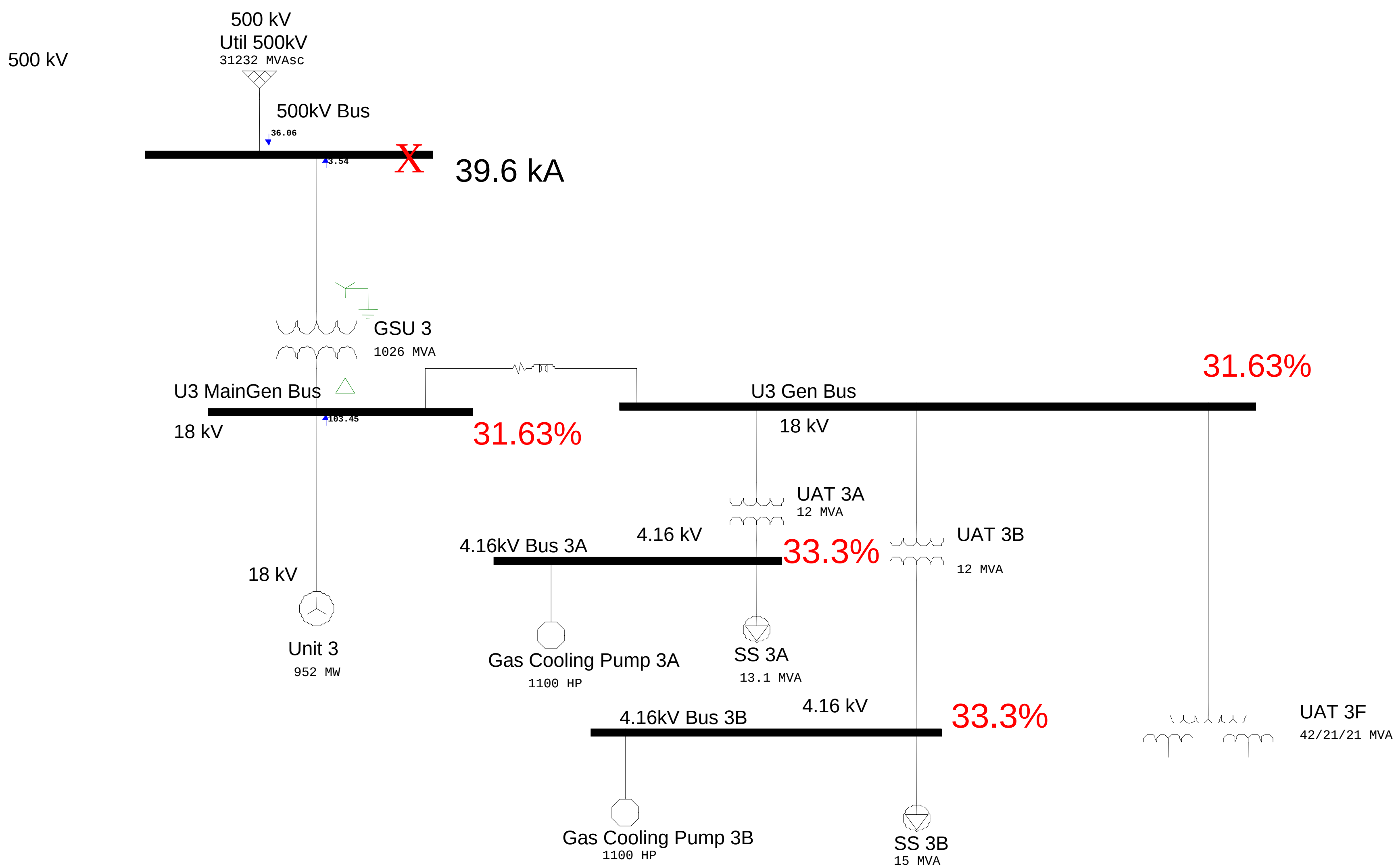
d. Backup Overcurrent Relays: Initially it was thought that these relays pose a potential problem. For the distance relay types, the trip setting is typically 75-120 cycles. Utilizing steady state solution techniques and the transmission voltages as shown on the LVRT curve, the generators would be supplying significant reactive current into the system for at least 90 cycles, which would cause the distance relays to trip. However, dynamic analysis has shown that the expected excitation system dynamics results in an expectation that these relays would not trip for the voltage excursion. The response of the voltage-restrained overcurrent type applied to some units would be even more difficult to obtain but could also be an issue.

C. Conclusion:

Overall, our review indicates more significant concerns with a unit/plant being able to remain on line during the UV event than the UF event. The overall opinion is for the proposed voltage profile that many generating units may potentially trip. However, a unit by unit study would be required to evaluate the probability.

Typical Plant and Normal Station Service

Generator and 4160V (Unit Fed) Bus Voltages for Switchyard 3ϕ Bus Fault

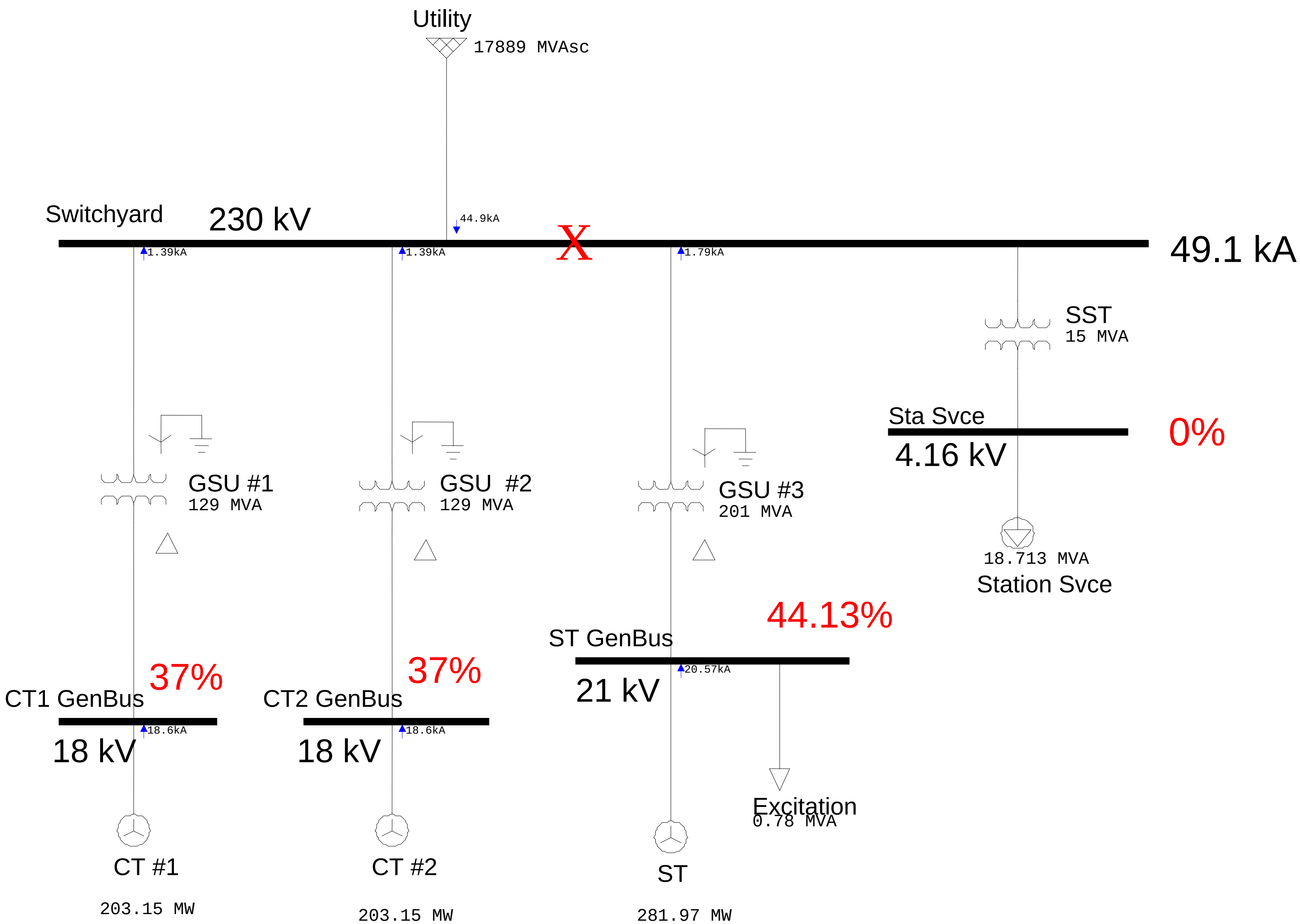


Notes:

1) Values computed using ETAP 30 cycle fault analysis function.
2) All bus voltages in % of rated bus voltage.

Typical Combined Cycle Unit

Generator and 4160V (Unit Fed) Bus Voltages for Switchyard 3ϕ Bus Fault



SERC Phase III-IV Field Test Results

Roger Green
Sharma Kolluri
Lee Taylor

June 18 - 19, 2007

Tampa, FL

Background

- SERC Volunteered for Phase III-IV Field Test in February 2006
- SERC Engineering Committee formed the Generator Standards Field Test Task Force
- NERC effort and SERC GSFT-TF activities officially began late May 06
  – SERC member entities volunteering include U.S. Army Corp of Engineers, Dominion, Entergy, South Carolina Electric & Gas, and Southern Company

Background

- GSFT-TF developed Field Test Guidelines and Reporting Forms for each draft Reliability Standard
  - These are <u>not</u> approved SERC procedures, standards, processes, etc.
  - Guidelines do contain details on “how” to implement the draft Reliability Standard requirements
  - Reference Attachment 1 in GSFT-TF Field Test Report
- Volunteer SERC entities used Reporting Forms as the basis of reporting their results

MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions

- All SERC volunteer entities attempted to participate
  - 1 GO was unable to schedule Open Step in Voltage test
- Noteworthy Observations include:
  - In general, the end result is more accurate excitation system models
  - Process is expensive if Consultants are utilized

MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions

- Noteworthy Observations continued:
  - After the Open Step in Voltage test, significant effort can be required to subsequently validate the model
    - Example – new static VR with existing rotating field exciter
  - To keep human and capital costs reasonable, GSFT recommends:
    - Exempt 75 MVA units and those interconnected < 100 kV
    - Allow sister unit and configuration controls

MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions

- Noteworthy Observations continued:
  - Standard should include a list of acceptable models
  - Standard should list TP as an Applicable entity
- The GSFT-TF recommends a 7 year phase in period
  - 2 years effective date after adoption, then 20% a year for 5 years

PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

- All SERC GO volunteers participated
- 1 GO has been performing studies for a number of years
  - Found one limiter mis-coordination out of 130 studies
- Other GOs only performed study on one unit for proof of concept
  - Significant start up cost (manpower and tools)
  - no mis-coordination found
- Total cost for SERC anticipated to be up to $16M

PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

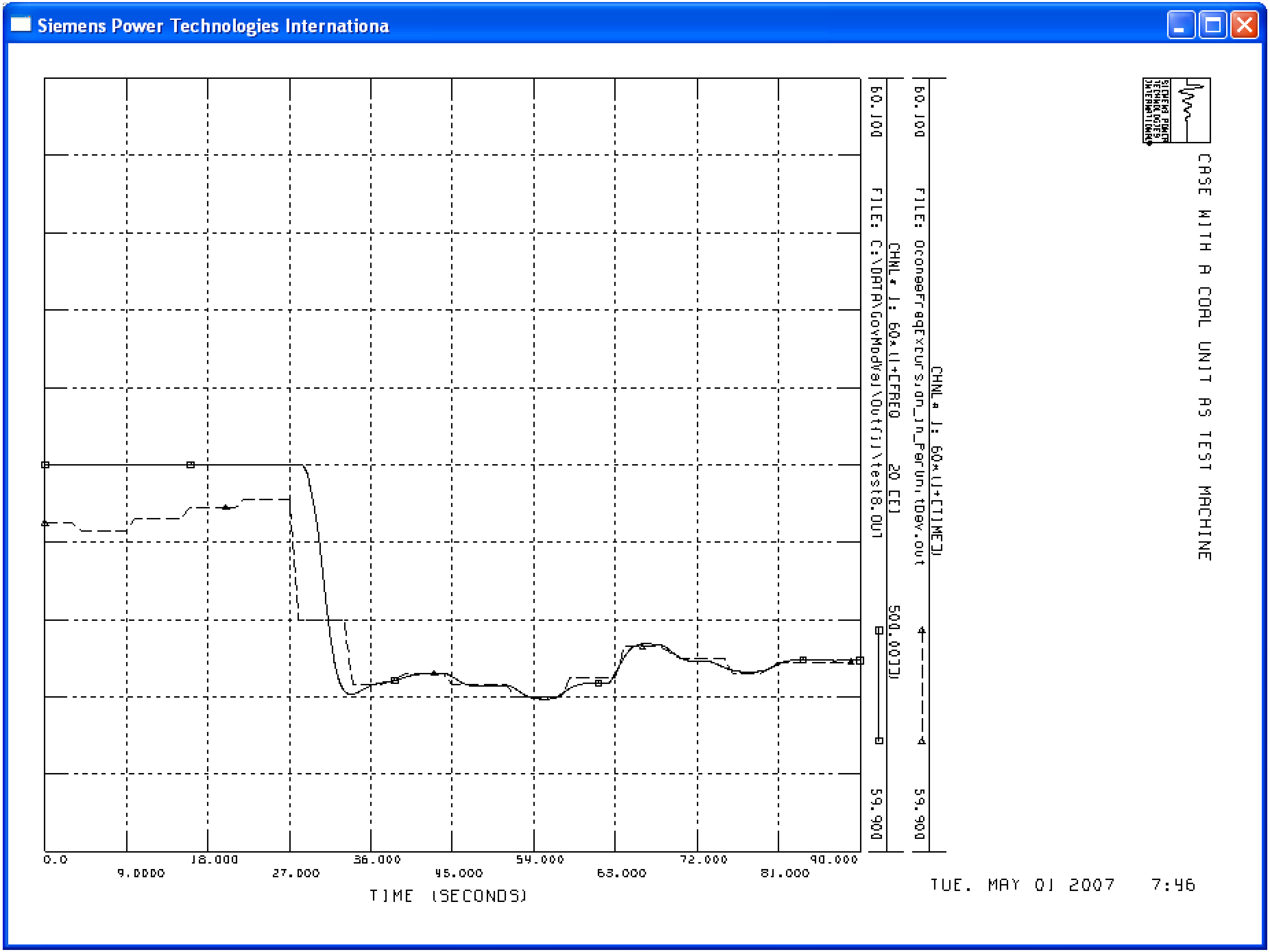
- Noteworthy Observations
  - GSFT recommends exemptions should include:
    - 75 MVA units and those interconnected < 100 kV
    - Older units
  - Requirement to plot prime mover limit adds no value
  - Requirement to plot additional limits that restrict MW or Mvar capability is ambiguous

PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

- Other Noteworthy Observations
  - GO should retain latest study and provide it to the Compliance Monitor upon request
  - Phase in period as currently drafted is acceptable (20% per year for 5 years)
  - Though costs are high, GSFT-TF recognizes the merit in moving the draft Reliability Standard forward

MOD-027-1 — Verification of Generator Unit Frequency Response

- All SERC volunteer entities attempted to participate
- Event Based methodology chosen
  - Small bus dynamics ready load flow and dynamics code developed to re-create the actual recorded Transmission System frequency excursion
  - Simulated governor model MW output is compared to actual unit MW event data
  - 2 Eastern Interconnection frequency excursion events evaluated


Siemens Power Technologies Internationa
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CHNL# 1: 60*(1+[FREQ 20 [E] 500.00]])
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59.900
0.0
9.0000
18.000
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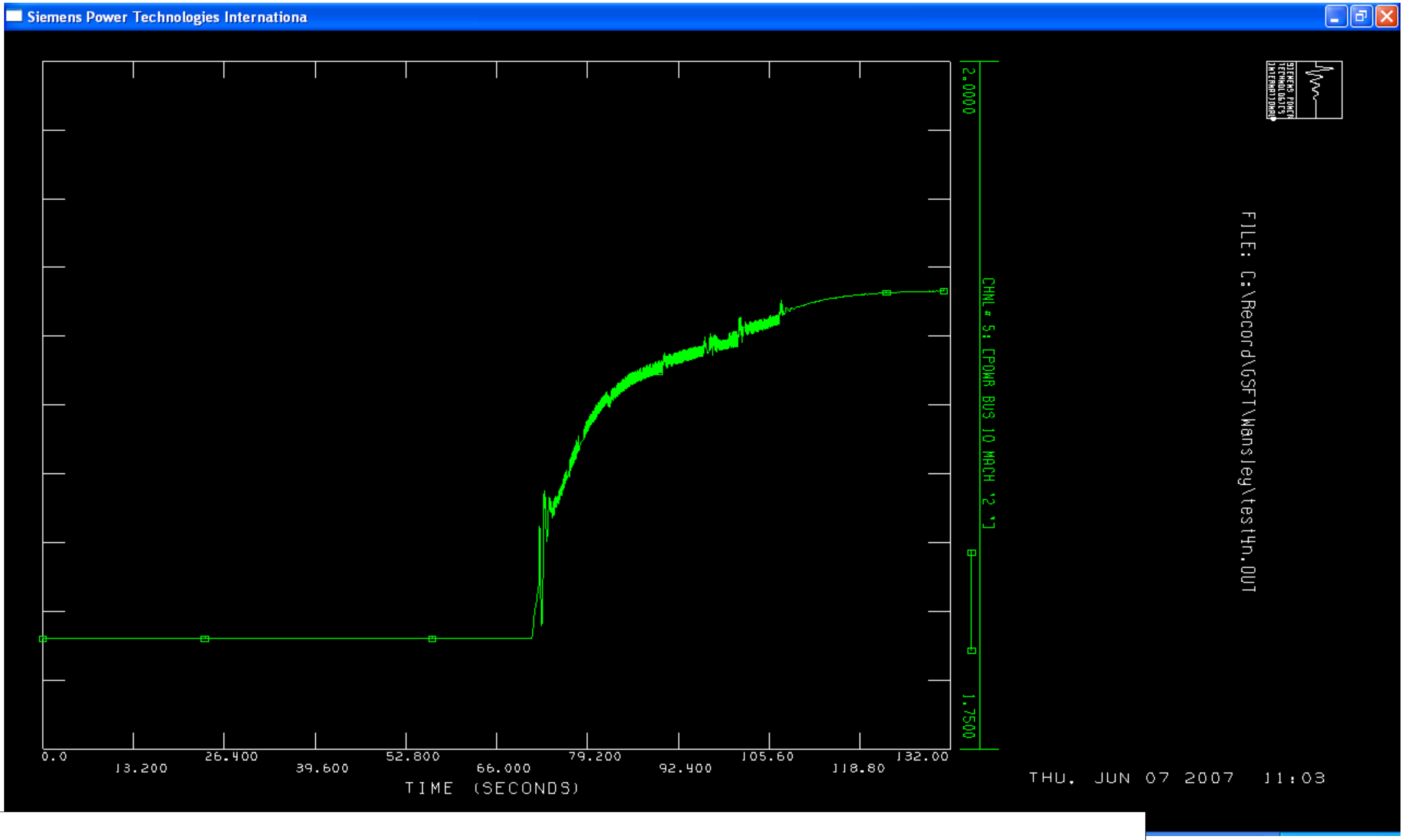

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1.7500
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13.200
26.400
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TIME (SECONDS)
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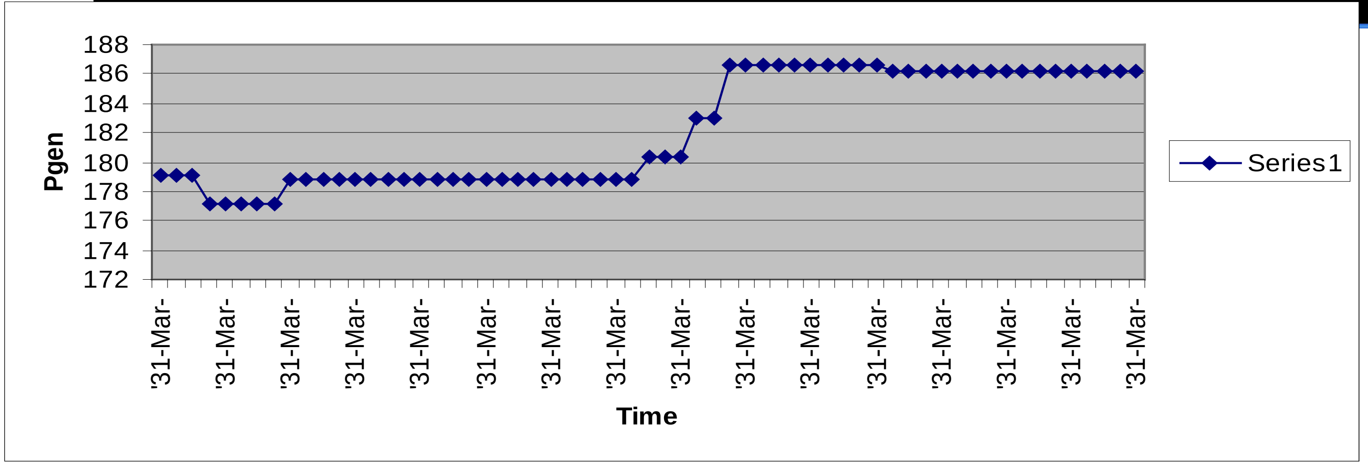

188
186
184
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176
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Pgen
'31-Mar-
Time
Series1

MOD-027-1 — Verification of Generator Unit Frequency Response

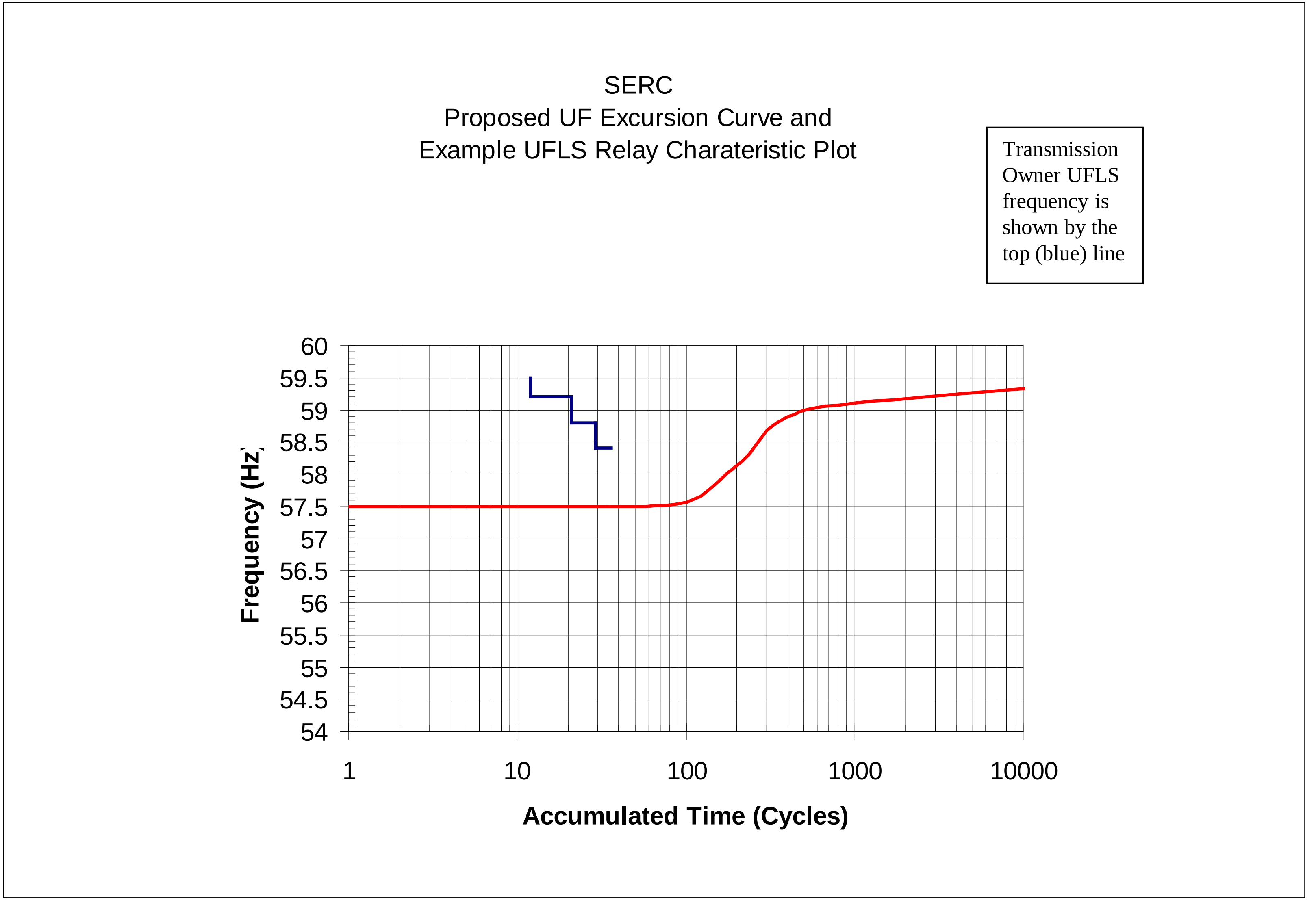
- Noteworthy Observations:
  - GSFT-TF believed that “proof of concept” was achieved
  - Not yet a “production grade” process required for a NERC Reliability Standard
    - Tool development
    - Recording Equipment (excluded participation by one GO)
  - Other obstacles to overcome
    - Process for identifying events in the Eastern Interconnection
    - Periodicity of frequency excursions relative to units being on-line but below Pmax (reason why one GO was not able to participate)

MOD-027-1 — Verification of Generator Unit Frequency Response

- GSFT-TF recommends this standard be "delayed" until issues with tools and processes are worked out
  - If Reliability Standard moves forward, recommend
    - a minimum 2 year delay after adoption, then 20% per year for the next 5 years with allowances for units not being on-line between Pmin and Pmax during identified frequency excursions
    - Exempt 75 MVA units and those interconnected < 100 kV
    - List TP as an Applicable entity

PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- 3 GOs and corresponding TOs participated
- Draft UF Ride Through Curve developed
  - UFLS relays need to be set above curve, and generation protection or operational limits below the curve
  - A curve acceptable to all the participants was developed
    - Disclaimer – other GOs would need to perform their own evaluations


SERC
Proposed UF Excursion Curve and
Example UFLS Relay Charateristic Plot
Transmission Owner UFLS frequency is shown by the top (blue) line
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
1
10
100
1000
10000
Accumulated Time (Cycles)

PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- Draft Low Voltage Ride Through Curve developed
  - Reliability need for UV safety net schemes design
  - Draft Reliability Standard as written only calls for "coordination of generator protection….."

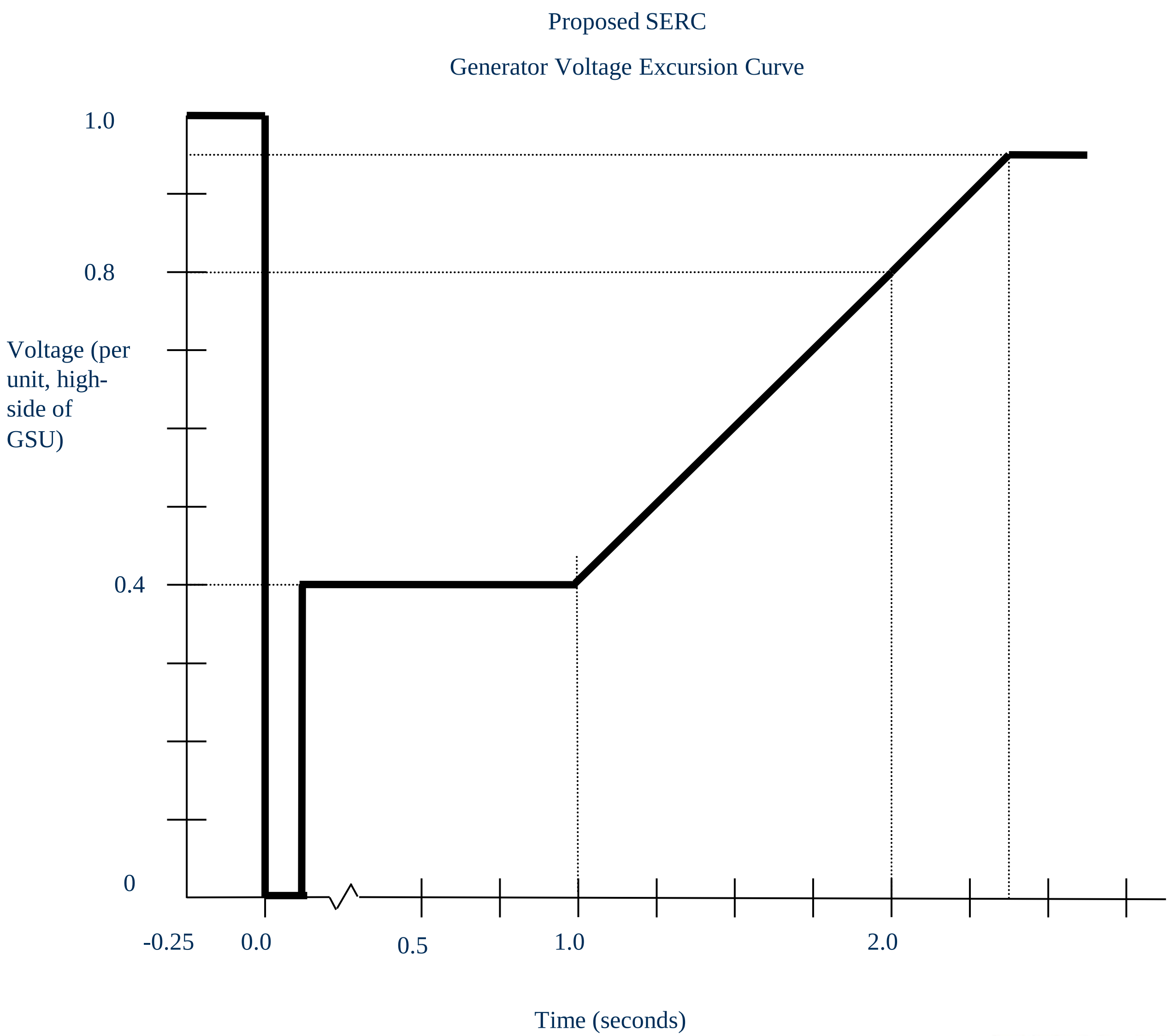

Proposed SERC
Generator Voltage Excursion Curve
1.0
0.8
0.4
0
Voltage (per unit, high-side of GSU)
-0.25
0.0
0.5
1.0
2.0
Time (seconds)

Figure 4

PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- Generator relay of most concern is Backup Impedance
  - Steady state evaluation resulted in incorrect conclusion that relay would operate for LVRT curve
  - Dynamic simulation showed that the expected exciter dynamics would not result in operation of relay

Proposed SERC

Generator Voltage Excursion Curve

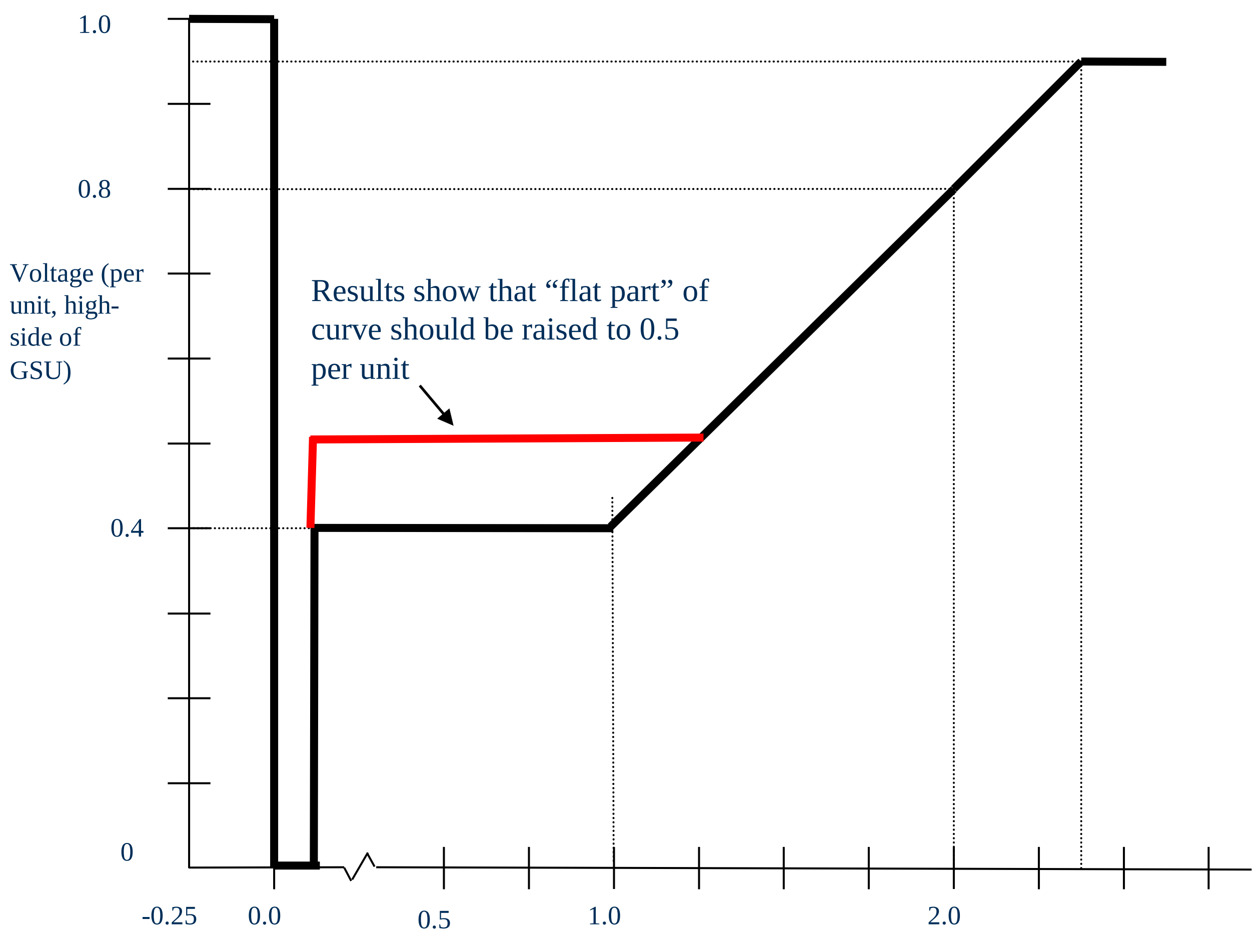


Figure 4

PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- Noteworthy Observations
  - For design of applicable UV schemes, Transmission Planners really need affirmation of assumption that unit can ride through a voltage excursion
  - As written, the draft Standard addresses only generation protective relays coordination and ride through
  - Standard does not address plant systems that could be limiting factor for ride through capability
  - However, assessment of these plant systems to ensure ride through capability is impractical
- Bottom line – additional research is required

Questions?

John Loftis	Dominion
Larry Whanger	Dominion
Art Howell	Entergy
Stan Jaskot	Entergy
Sharma Kolluri	Entergy
Pat Longshore	SCE&G
Pat Huntley	SERC
Roger Green	Southern
Tom Higgins	Southern
Lee Taylor	Southern
David Williams	US Army Corps of Engineers

For additional information

www.serc1.org

Or contact any SERC EC GSFT-TF Member

WECC compliance with NERC draft Standards for 2006 Field Test

Mod-026, Mod -027, Prc-019, PRC-024

<table>
<tr><td>NERC Standard Requirement</td><td>WECC Document Reference</td></tr>
<tr><td>From Mod-026-1

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of models and data associated with generator excitation system functions including voltage regulator controls, limiters, compensators, and power system stabilizers. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.</td><td>From the WECC Generating Unit Model Validation Policy (Policy) approved July 2006

A.3. Applicability:

A.3.1. Facilities Affected: This policy statement applies to generating facilities connected to the Western Electricity Coordinating Council (WECC) transmission grid at 60 kV or higher voltage (both new and existing, synchronous and non-synchronous) with single unit capacity of 10 MVA and larger, or facilities with aggregate capacity of 20 MVA and larger.

A.3.2. Baseline Testing

A.3.2.1. The Generator Owner shall test the generating unit and validate its model data.

The associated reference documents (with the Policy) titled Generating Unit Baseline Test Requirements and Generating Facility Model Validation Requirements describe methods for verification of the various data items and conditions under which they must be verified.</td></tr>
</table>

R1.3. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.	According to the policy, generator owners are required to perform initial tests to validate data, then they are required to validate the data after changes to generator systems, and verify the data every 5 years or if the transmission planner has reason to suspect the data. They are required to provide the reports to the transmission planner, who review the report and provide it to WECC
R1.4. Information to be reported related to generator excitation system functions: **R1.4.1.** Verified manufacturer and type of excitation system/voltage regulator control system (for example, static, brushless, rotating, etc.). **R1.4.2.** Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits. **R1.4.3.** Verified static set points for under and over excitation limiters. **R1.4.4.** Verified line drop compensator settings. **R1.4.5.** Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units). **R1.4.6.** Verified model for each power system stabilizer with associated gains, time constants, and limits. **R1.4.7.** Confirmation that the verification was conducted with the voltage regulator in the automatic voltage control mode **R1.4.8.** Method of verification used. **R1.4.9.** Date of verification.	The reference document titled *Generating Facility Data Requirements* section 2.2 describes requirements for data to be reported regarding the excitation system. All of these items are mentioned.

R2. The Regional Reliability Organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval. **R3.** The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its models and data associated with generator excitation system functions per MOD-026 R1.	The generator test policy is posted on the public WECC web site to assure availability to those that need it.
From Mod-027-1 **R1.** The Regional Reliability Organization shall establish and maintain procedures to address verification of generator unit frequency response. These procedures shall include the following: **R1.1.** Response time to be modeled, e.g. up to 30 seconds for steam units, up to 45 seconds for hydro units, etc. **R1.2.** Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures. **R1.3.** Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of	Covered in the documents titled *Generating Unit Baseline Test Requirements* and *Generating Facility Model Validation Requirements* **A.3. Applicability:** A.3.1. **Facilities Affected:** This policy statement applies to generating facilities connected to the Western Electricity Coordinating Council (WECC) transmission grid at 60 kV or higher voltage (both new and existing, synchronous and non-synchronous) with single unit capacity of 10 MVA and larger, or facilities with aggregate capacity of 20 MVA and larger. Covered in the documents titled *Generating Facility Data Requirements* and *Generating Facility Model Validation Requirements*

manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.	
R1.4. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.	From the *WECC Generating Unit Model Validation Policy* (Policy) approved July 2006
R1.5. Information to be reported related to generator unit frequency response: **R1.5.1.** Verified manufacturer and type of speed governor controls. **R1.5.2.** Verified model for each speed governor control with any associated deadband, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.). **R1.5.3.** Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response). **R1.5.4.** Method of verification and conditions of the verification including status of controls.	Covered in the documents titled *Generating Facility Data Requirements* and *Generating Facility Model Validation Requirements*
R2. The Regional Reliability Organization shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 calendar days of the	The generator test policy is posted on the public WECC web site to assure availability to those that need it.

approval. **R3.** The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying and reporting its generator unit frequency response per MOD-027 R1.	
From PRC-019-1 **R1.** The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the Generator Owner requirements in R2.	**A.3. Applicability:** A.3.1. **Facilities Affected:** This policy statement applies to generating facilities connected to the Western Electricity Coordinating Council (WECC) transmission grid at 60 kV or higher voltage (both new and existing, synchronous and non-synchronous) with single unit capacity of 10 MVA and larger, or facilities with aggregate capacity of 20 MVA and larger.
R2. Unless exempted by the Regional Reliability Organization in accordance with R1, the Generator Owner shall have study results that show it verified that its generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. This study shall include the following: **R2.1.** Plots, or data that could be plotted for the following: **R2.1.1.** Generator capability curve, including specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure. **R2.1.2.** Steady state over-excitation limiter and under-excitation limiter control characteristics. **R2.1.3.** MW limit of the prime mover. **R2.1.4.** Any other limit that could restrict the megawatt or megavar capability. **R2.1.5.** Loss of excitation / field	Covered in the document titled *WECC Generating Facility Data Requirements*

protective relay characteristics. **R2.1.6.** Volts-per-hertz protection settings including volts-per-hertz limiters in the automatic voltage regulator. **R3.** The Generator Owner shall have the information in R2.1.1 through R2.1.6 available to show to the Regional Reliability Organization upon request (within 30 calendar days).	
From PRC-024-1 **R1.** The Regional Reliability Organization shall establish requirements for generators to remain connected during system frequency and voltage excursions expressed as a function of: **R1.1.** Time duration in seconds or cycles. **R1.2.** Amplitude or magnitude of the excursion. **R1.3.** Relationship between time and amplitude or magnitude.	Frequency requirements are covered by the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements. Reference A section X. Proposed Voltage Standards cover these items for faults and there is a proposed voltage versus fault clearing time curve. Voltage is also listed with regard to coordination with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements in Section XII.
R2. The Regional Reliability Organization shall establish and maintain requirements for generators to remain connected during frequency and voltage excursions. These requirements shall include: **R2.1.** Coordination between the generator under frequency protection and the regional Under Frequency Load Shedding (UFLS) program.	This is covered in the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements. Section X
R2.2. Coordination of generator protection, including back-up protection, with transmission Protection Systems.	WECC policy including the *NERC/WECC Planning Standards* and the *Minimum Operating Reliability Criteria* specify that these be coordinated.
R3. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the regional requirements established in accordance with R1 and R2. **R4.** The Regional Reliability Organization shall establish and maintain a procedure for handling variances (i.e., different criteria or	In the Off-Nominal Plan the exemption method is listed in Section X Recommendation 5B. It specifies that load must be tripped to match generation that trips too quick. A similar requirement may be needed in the Voltage Standard. The currently proposed voltage standard indicates a 10 MVA size threshold.

methods) from the Regional Reliability Organization's requirements established in R1 and R2, including steps for requesting and approving such variances. **R5.** The Regional Reliability Organization shall provide documentation of its excursion requirements, exemptions, and variance procedure to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval. **R6.** The Regional Reliability Organization shall, at least every five years, review and, as necessary, update its requirements, exemption criteria, and variance procedure. **R7.** Generator Owners and Transmission Owners shall comply with the regional requirements for coordination of generator protection defined in R2 and any approved variances.	WECC has had organizations that requested variances by submitting a request to the appropriate WECC Committees – Subcommittees and work groups. The documents should be reviewed to assure that they specifically indicate the process for obtaining variances.

WESTERN ELECTRICITY COORDINATING COUNCIL

GENERATING UNIT MODEL VALIDATION POLICY

A. Introduction

A.1. Title: Generating Unit Model Validation Policy

A.2. **Purpose:** Accurate models of generators and associated controls are necessary for realistic simulations of the electric power system of the western interconnection. Baseline testing and periodic performance validation are required to ensure that the dynamic models and databases that are used in the grid simulations are accurate and up to date.

A.3. Applicability:

A.3.1. **Facilities Affected:** This policy statement applies to generating facilities connected to the Western Electricity Coordinating Council (WECC) transmission grid at 60 kV or higher voltage (both new and existing, synchronous and non-synchronous) with single unit capacity of 10 MVA and larger, or facilities with aggregate capacity of 20 MVA and larger.

A.3.2. Entity Responsible:

A.3.2.1. Generator Owner
A.3.2.2. Transmission Planner
A.3.2.3. Regional Reliability Organization

A.4. References: The following documents referred to in this Policy are posted in the "Generator Testing Program" area on the WECC website at [www.wecc.biz]:

A.4.1. Generating Facility Data Requirements
A.4.2. Generating Unit Baseline Test Requirements
A.4.3. Generating Unit Model Validation Requirements
A.4.4. List of WECC-Approved Models

A.5. Effective Date: Approved by the Board at the meeting July 26-28, 2006.

B. Requirements

B.1. Generator Owner Responsibilities

B.1.1. Generating Facility Data

B.1.1.1. The Generator Owner shall provide to the Transmission Planner the information for the Generating Facility as specified in the *Generating Facility Data Requirements* document.

B.1.1.2. The Generator Owner shall review, verify and update the Generating Facility data when any of the following conditions occur:

B.1.1.2.1. No later than 180 days after the new Generating Facility is released for Commercial Operation.

B.1.1.2.2. No later than 180 days after an existing generating unit re-starts Commercial Operation with modified equipment, control settings, or software that influences the behavior of the plant with respect to the grid (e.g. excitation retrofit, additional control function within a controller, turbine modification, voltage regulator and power system stabilizer tuning modification, etc.)

B.1.1.2.3. At least once every five years.

B.1.2. Baseline Testing

B.1.2.1. The Generator Owner shall test the generating unit and validate its model data.

B.1.2.2. The Generator Owner shall provide test and validation reports to its Transmission Planner.

B.1.2.2.1. For guidance on the test requirements, refer to the current *Generating Unit Baseline Test Requirements* document.

B.1.2.3. The testing and associated validation by simulation shall be performed on a generating unit when any of the following conditions have occurred:

B.1.2.3.1. If the generating project has not been certified by WECC under Generator Testing Program since January 1997.

B.1.2.3.2. No later than 180 days after the new Generating Facility is released for Commercial Operation. In the meantime, the Generator Owner will provide the best available model data supplied by the equipment manufacturer using the WECC approved models including commissioning reports.

B.1.2.3.3. No later than 180 days after an existing generating unit re-starts Commercial Operation with modified equipment, control settings, or software that influences its behavior with respect to the grid (e.g. excitation retrofit, additional control function within a controller, turbine modification, voltage regulator and power system stabilizer tuning modification, etc.), only those portions of the generating unit model that can be influenced by the modifications need to be tested and validated.

B.1.2.3.4. No later than 180 days after the Generator Owner is notified by WECC that there is evidence that the modeled response of a Generating Facility does not correlate with the actual response, except in instances where the lack of correlation was caused by equipment problems that were subsequently corrected.

B.1.3. Model Data Validation

B.1.3.1. The Generator Owner shall perform model data validation and provide a report to its Transmission Planner at least once every five years. Schedule of model validation shall be coordinated between the Generator Owner, Transmission Planner and Transmission Operator

B.1.3.1.1. The *"Generating Facility Model Data Validation Requirements"* document describes acceptable methods of model data validation by performance comparison.

B.1.3.2. Generator Owner shall verify that generator control limiters, protection and equipment capabilities are consistent with those reported in the model(s).

B.2. Transmission Planner Responsibilities

B.2.1. Model Data Validation

B.2.1.1. The Transmission Planner shall maintain a current list of all Generating Facilities in its planning area that are subject to testing and model data validation.

B.2.1.1.1. This list shall be made available to WECC upon request.

B.2.1.1.2. For each Generating Facility, the list shall include the status of compliance with this Generating Unit Model Validation Policy, including report dates.

B.2.1.2. The Transmission Planner shall notify Generator Owner when generating unit re-testing and validation are required to maintain compliance with this policy.

B.2.1.3. Disturbance data recorded either at the generator or at the point of interconnection can be used for model data validation.

B.2.1.3.1. If the Transmission Planner has performance monitoring equipment at the point of interconnection, the data shall be made available to the Generator Owner, upon request.

B.2.2. Facility Data and Validation Reports

B.2.2.1. The Transmission Planner shall collect Generating Facility data and model data validation reports from Generator Owners.

B.2.2.2. The Transmission Planner shall verify that the WECC-approved model parameters provided by the Generator Owner are adequately validated by comparing the simulated response of the unit against either the recorded baseline tests or a disturbance response as the case may be, within 30 calendar days after receipt from the Generator Owner.

B.2.2.2.1. The Transmission Planner will work with the Generator Owner on resolving the differences between simulated and actual responses of the Generating Facility to grid disturbances. The Transmission Planner will inform WECC if the differences cannot be resolved.

B.2.2.3. The Transmission Planner shall submit the accepted validated models to WECC and shall notify the Generator Owner that the models are accepted.

B.2.2.4. If a model data validation report is rejected, the Transmission Planner shall inform the Generator Owner of the reason(s) for the rejection. The Transmission Planner will work with the Generator Owner to expedite resolution of any issues preventing acceptance of the model data validation report. The Transmission Planner will inform WECC if the issues cannot be resolved.

B.3. WECC Responsibilities

B.3.1. WECC shall maintain a master data file with the current validated models.

B.3.2. WECC shall review and approve the generator testing and model validation reports.

B.3.3. WECC shall verify that the models are stable and that the modeled system responses reasonably match power system performance.

B.3.4. WECC shall verify compliance with the certification requirements, issue certificates to the Generator Owners and notify Transmission Planner.

B.3.5. WECC has the final authority to determine the suitability of testing and validation of the models.

B.3.6. WECC periodically shall audit the Generator Owners and Transmission Planners on the status of generator testing and model validation.

B.3.7. WECC periodically shall review technical requirements listed in section A4. Any changes in the requirements will go through a WECC "due process."

B.4. Exemptions

B.4.1. WECC may grant exemptions to the Generator Owners in rare situations where a unique condition or equipment configuration exists that would preclude or delay testing and model data validation.

B.4.2. The Generator Owner may request an exemption by submittal to WECC through the Transmission Planner. The request shall include justification for the exemption. WECC shall respond to the request within 90 days after receipt.

C. Definitions

Generator Owner is defined in NERC Reliability Functional Model.

Transmission Planner is defined in NERC Reliability Functional Model.

Commercial Operation is defined in FERC 2003-A Standardization of Generator Interconnection Agreements and Procedures.

Generating Facility is defined in FERC 2003-A Standardization of Generator Interconnection Agreements and Procedures.

Validation. Within the context of this policy and associated documents, Validation is used synonymously with verification and refers to the process of selecting parameters for the appropriate WECC-approved models for generating units and demonstrating that the model behavior is consistent with the generating unit behavior by comparison of simulation to test recording.

Western Electricity Coordinating Council

Generating Facility Data Requirements

1. Principal one-line electrical diagram of the generating facility

Provide a principal one-line diagram of the generating facility, identifying individual generating units, transformers (main step-up, unit auxiliaries, excitation source), transmission lines associated with the generation facility, station service loads, and any other relevant electrical equipment (e.g. power-factor capacitors, static var compensators).

2. Generating Unit Data

Label the generating unit number or identifier in the plant diagram

2.1. Synchronous Generator Data

Provide synchronous generator nameplate data, including rated MVA, kV, stator Amps, power factor, RPM, exciter voltage, rotor Amps.

Provide synchronous generator parameters:

Impedance Data in per unit on machine rated MVA and kV		
Synchronous direct axis reactance – unsaturated	Xdi	
Synchronous quadrature axis reactance– unsaturated	Xqi	
Transient direct axis reactance – unsaturated	X'di	
Transient quadrature axis reactance – unsaturated (*)	X'qi	
Subtransient direct axis reactance – unsaturated	X"di	
Subtransient quadtaure axis reactance – unsaturated (*)	X"qi	
Leakage reactance	Xl	
Positive sequence resistance	Ra	
Field Time Constants		
Open circuit transient time constant – direct axis	T'do	
Open circuit transient time constant – quadrature axis (*)	T'qo	
Open circuit subtransient time constant – direct axis	T"do	
Open circuit subtransient time constant– quadrature axis	T"qo	
Combined Turbine-Generator(-Exciter) Inertia		
Inertia Constant	H	
Open-Circuit Saturation		
Saturation at 1.0 pu generator voltage	S1.0	
Saturation at 1.2 pu generator voltage	S1.2	

(*) not required for salient pole generators

Provide generator open circuit saturation curve with air-gap line.

Air gap field current at rated generator voltage ________________ Amps

Measured field winding resistance __________ Ohms

Field winding temperature or generator hot air/gas temperature at which the field winding resistance was measured __________ C

2.2. Excitation System Data

2.2.1. Exciter and Voltage Regulator

Excitation system type (static, ac rotating, brushless, dc generator, etc) and manufacturer: ____________________________________

Provide nameplate information on excitation equipment (such as excitation transformer in static exciters, dc generator and amplidyne in dc rotating exciters, main and pilot ac generators in ac rotating exciters)

Voltage regulator type and manufacturer (e.g., GE EX 2100, ABB Unitrol-F, etc)
____

Provide a block diagram and completed data forms for the corresponding WECC-approved model (document “WECC Approved Models”).

2.2.2. Line Drop Compensation/Reactive Current Compensation

Indicate whether the voltage regulator has a line drop compensation or reactive current compensation, and provide settings in per unit on machine rated MVA and kV.

2.2.3. Power System Stabilizer

PSS type and manufacturer (e.g., GE EX2000, Basler)
____

Provide a block diagram and completed data forms for the corresponding WECC-approved model (document “WECC Approved Models”).

2.2.4. Over-Excitation Limiter (OEL)

Provide fullest available information on OEL.

Indicate OEL type and manufacturer (e.g. Westinghouse MXL/OXP).

Describe OEL time characteristic (definite time, inverse time).

Provide pickup vs. time characteristic curve

Describe OEL actions (e.g., reduce field current below continuous current rating, trip voltage regulator into manual field current control, trip the generator.)

2.2.5. Under-Excitation Limiter (UEL)

Provide fullest available information on UEL.

UEL type (conventional or voltage sensitive, PQ-limiter, etc).

Describe UEL actions.

Provide limit settings as a curve of real and reactive power.

2.2.6. Stator Current Limiter

Is a stator current limiter incorporated into the excitation system?

Provide fullest available information on stator current limiter

2.2.7. High Voltage Bus Controllers, VAR limiters and Power factor controllers

Provide fullest available information on these controllers.

Indicate which of these controllers are active in normal operation.

2.3. Generator Reactive Capability Curves

Continuous field current rating ____________ Amps

For hydrogen-cooled generators, indicate hydrogen pressure during normal operating conditions ______ psi.

Provide machine reactive capability curves at rated voltage and nominal hydrogen pressure).

Superimpose generator control, limiter and protection curves on the machine reactive capability curve.

Define the operating reactive capability of the generator.

Provide information on reactive power limits implemented by plant or unit supervisory controls (e.g. plant DCS, GE Mark V/ Mark VI / Ovation, GDACS).

3. Turbine-Governor Data

3.1 Hydro-turbine generators

Hydraulic Turbine

Turbine type (e.g., Francis, Kaplan, Pelton) ____________________________

Nominal head ____________ ft   Typical range of operating heads__________ ft

Turbine capacity at full gate opening, nominal head ____________ MW

Provide the "Power versus Gate Position" characteristic at expected operating heads (for Kaplan turbines with blade on the cam). For Kaplan turbines, provide the "Blade angle versus Gate Position" characteristic at expected operating heads.

Provide contact information for a person for reference regarding hydraulic profile of the plant.

Water inertia starting time Tw___________ sec

Hydro Governor

Hydro governor type (e.g. Asea analog electronic, Woodward dash-pot, Woodward 505H, Voest Alpine electronic) ______________________

Provide a block diagram and completed data forms for the WECC-approved models (document "WECC Approved Models").

For Kaplan turbines, provide block diagram with relevant data for a blade controller.

3.2 Steam-Turbine

Boiler type (drum-type or once through) ____________________

Normal fuel type (coal, oil, gas, other) ______________________

Indicate whether the turbine is tandem-compound or cross-compound

Turbine capacity at rated steam throttle pressure, full valve opening
____________ MW

Rated steam pressure (HP) ____________________ psi

Governor type and manufacturer ____________________________

Boiler controller type and manufacturer ____________________________

Describe the normal turbine control and operating practice (base loaded, turbine follow, boiler follow, coordinated controller, sliding pressure, etc)

Provide a block diagram and completed data forms for the WECC-approved models (document "WECC Approved Models").

3.3. Gas Turbines

Gas turbine type and manufacturer (e.g. GE Frame 7, W-501, GE LM6000, etc)
____

Provide the maximum generator output as a function of ambient temperature.

For combined cycle plants,
If the plant has a steam cycle, describe how steam is used from a heat recovery steam generator (HRSG), e.g.

- all steam is used by a steam-turbine generator, or
- 40% of steam is for industrial use, or
- the project is using supplementary duct firing, all steam is used by a steam-turbine generator

Provide a block diagram and completed data forms for the WECC-approved models (document "WECC Approved Models.").

4. Power Plant Controls (e.g. GE Mark V, Ovation,)

4.1. Load or MW controller

Indicate whether the plant has an active load controller (e.g. Process Coordinated Controller).

Describe load controller functions:

- Does it keep the MW output of the plant at a specified set-point?
- Does it have a frequency bias and dead-band?

Provide recordings of plant response to system frequency excursions, if available.

Provide information on AGC capability, ramp rates (up and down), and ranges (low and high). Provide ramp rate recordings, if available.

4.2. Reactive Power Controller

Indicate whether the plant has any reactive power controller (high-side voltage controller, reactive power balancing among units, etc).

Describe the reactive power controller functions:

- Does the controller balance reactive power among generators in the plant?
- Does the controller perform high-side voltage control automatically and how fast it starts and completes response?
- Does the controller limit generator terminal voltage (e.g. +/- 5% of nominal)?

Provide SCADA recordings of plant response to system voltage deviations, if available, showing the effect of the plant reactive power controller.

5. Transformers

Provide the following information for each of the transformers identified in the principal one-line diagram of the generating facility.

Application *(GSU/CSU/LT):* _________________
Number of Windings *(2 or 3):* ________________
Indicate whether the unit is an autotransformer: __________
Note: Subsequent data in rows identified with asterisk (*)are required only for 3-winding transformers

Winding Data

Winding	Nominal	Configuration	Nameplate MVA Ratings		
	[kV]	[Δ, Y, YG]	FA	FO	FOA
Primary – H					
Secondary – X					
(*) Tertiary – Y					

Impedance Data (base MVA= ______ base kV= _____) :

Windings	R1	X1	R0	X0
H to X				
(*) H to Y				
(*) X to Y				

Tap Changer

Tap Changer	Tap Position [kV or Percent]			
Winding	Operating	Min	Max	Step
(H, X, or Y)				

For on-load tap changers, specify the following:

- Regulated voltage: ____________ percent, or Volts
- Controlled bus: ____________
- Dead-band: ____________ percent, or Volts
- Tap changer time constant: _____________ sec

6. Line Data

Provide the following data for each of the lines and feeders identified in the principal one-line diagram of the generating facility:

Nominal operating voltage, kV	
Line length, mi	
Positive sequence line resistance, Ω	
Positive sequence line reactance, Ω	

Please indicate whether the line is overhead or underground.

7. Auxiliary Load

Provide auxiliary load MW and MVAR at minimum stable and maximum power output.

Auxiliary load may be identified as any load at utilization voltage less than the transmission system interconnection voltage, including station service load and unit service load.

Western Electricity Coordinating Council

Generating Facility Model Validation Requirements

Dynamic response validation

The essential principle of dynamic response validation is that the chosen model of the generating facility in the PSS/E or PSLF program must reproduce the results of tests or reproduce recorded disturbances within normally acceptable levels of accuracy.

This principle must be met by executing simulations of the tests or recorded system events in the PSS/E or PSLF program so as to demonstrate that:

- signals from the tests or recorded events are used as reference data
- clearly identifiable variations of input variables are presented to the model to impose the test or recorded disturbance on the model
- the result signals obtained from the simulation are compared to and agree with the reference data

The measure of success of the validation is the quality of the agreement between the recorded and simulated results. Important response characteristics include the following:

- general shape of the curves, including magnitude and rate of the response;
- rise time, overshoot and bandwidth;
- dead-bands and delays;
- initial and final values.

Option 1. Validation using Recordings taken at the Point of Interconnection of the Generating Facility.

Validation is performed using disturbance recordings taken at the Point Of Interconnection (POI) of the Generating Facility (see Figure 1).

The dynamic response of the Generating Facility is driven by the voltage and frequency at the POI and the control inputs (e.g. due to voltage and power schedules from the Control Area Operator).

The POI voltage (V), POI frequency (f), and the unit control signals are used as the model inputs. The real (P) and reactive (Q) power are the measures of the model performance. The validation shall be done for events of voltage and frequency deviations and oscillations at the point of interconnection.

The minimum sampling rate is 20 samples per second. The minimum disturbance record length is 30 seconds.

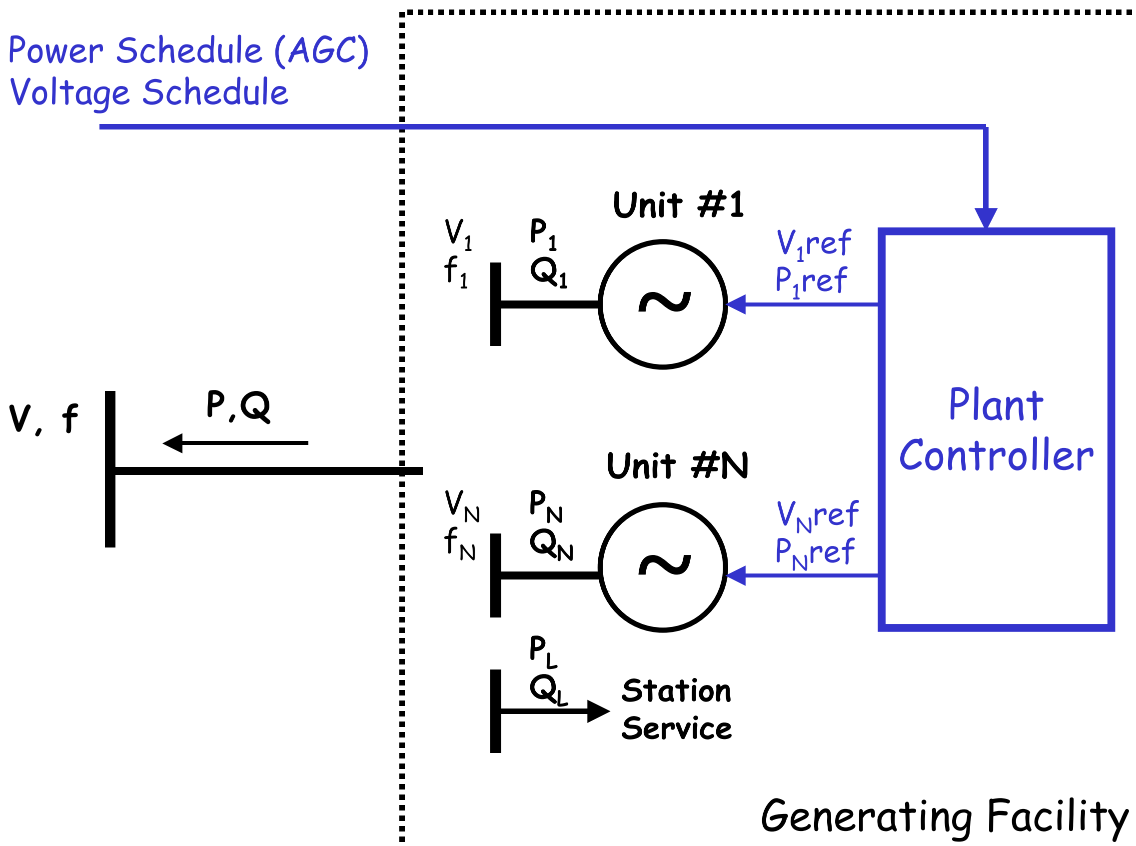


Figure 1: validation performed using disturbance recordings taken at the Generating Facility POI

Acceptable validation methods for generator – excitation models:

Event	Input to Model	Validation Signal
(i) Sudden change in voltage at point of interconnection (greater than 2%) due to a disturbance	- voltage at point of interconnection - frequency at point of interconnection - control signals	- power at point of interconnection - reactive power at point of interconnection
(ii) Sudden change in Generator reactive power (greater than 10% of rated MVA) due to a disturbance	- voltage at point of interconnection - frequency at point of interconnection - control signals	- power at point of interconnection - reactive power at point of interconnection

Acceptable validation methods for governor-turbine models:

Event	Input to Model	Validation Signal
(i) Sudden frequency changes (greater than 0.05 Hz) due to disturbance	- frequency at point of interconnection - control signals	- power at point of interconnection

Examples of governor response validation are described in the following IEEE papers:

1. Les Pereira, John Undrill, Dmitry Kosterev, Donald Davies and Shawn Patterson, “A New Thermal Governor Modeling in WECC,” *IEEE Transactions on Power Systems*, vol.18, no.2, pp.819-829, May 2003.

2. Les Pereira, Dmitry Kosterev, Donald Davies and Shawn Patterson, “New Thermal Governor Model Selection and Validation in the WECC,” *IEEE Transactions on Power Systems*, vol.19, no.1, pp.517-523, February 2004.

3. Dmitry Kosterev, “Hydro Turbine-Governor Model Validation in Pacific Northwest,” IEEE Transactions on Power Systems, vol.19, no.2, pp.1144-1149, May 2004.

Option 2. Validation using Recordings taken at the Generating Unit.

Validation is performed using disturbance and/or test recordings taken at the Generator (see Figure 2). This should be done for every Generator in the Generating Facility.

The dynamic response of the Generator is driven by the stator voltage and frequency (or real and reactive load). The response can be also initiated by the control inputs such as voltage reference and speed reference.

Validation shall be done for the following events:
a) disturbances or tests that result in generator stator voltage and reactive power changes.
b) disturbances that result in generator frequency changes or tests that result in generator real power changes.

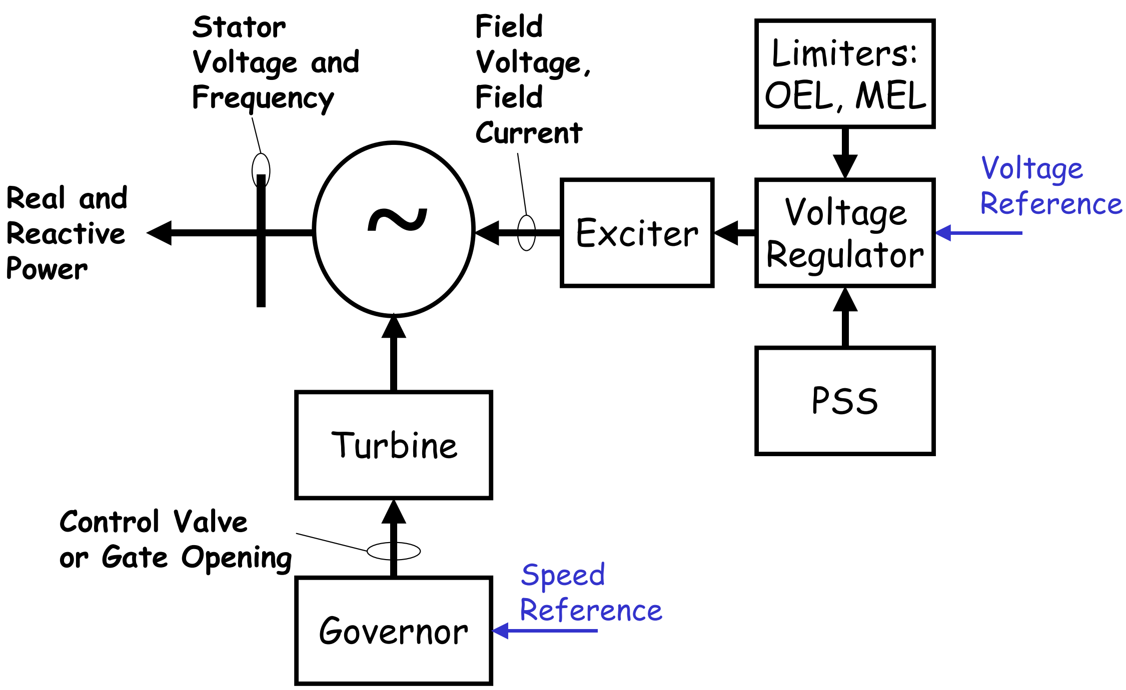


Figure 2: Validation is performed using disturbance and test recordings taken at the Generator

Acceptable validation methods for generator – excitation models:

Event	Input to Model	Validation Signal
(i) Voltage Reference step (typically 2%) with Generator on-line	- Voltage reference step - Generator real power - Generator reactive power	- Stator Voltage - Field Voltage (or Exciter Field Current for rotating exciters)
(ii) Voltage Reference step (typically 2%) with Generator off-line	- Voltage reference step	- Stator Voltage - Field Voltage (or Exciter Field Current for rotating exciters)
(iii) Sudden change in Generator reactive power (greater than 10% of rated MVA) due to a disturbance with Generator on-line	- Generator real power - Generator reactive power	- Stator Voltage - Field Voltage (or Exciter Field Current for rotating exciters)
(iv) reactive load rejection	- Generator reactive power	- Stator Voltage - Field Voltage (or Exciter Field Current for rotating exciters)
(v) Frequency response of Vt/ Vref	- Voltage reference swept sine	- Stator Voltage

The minimum sampling rate is 20 samples per second.

Acceptable validation methods for governor-turbine models:

Event	Input to Model	Validation Signal
(i) Speed Reference steps with generator on-line	- Speed Reference - Frequency	- Generator real power
(ii) Sudden frequency changes (greater than 0.05 Hz) due to disturbance with Generator on-line	- Frequency	- Generator real power

The maximum sampling period is 4 seconds – data available from SCADA or plant DCS.

Western Electricity Coordinating Council
Generating Unit Baseline Test Requirements

A great amount of technical information on methods of generator testing is provided in WSCC 1997 Generator Test Request Letter and Guidelines posted on WECC web-site [www.wecc.biz].

1. Synchronous Generators

The following tests shall be done:

a. Open Circuit Saturation: Measurement of the steady state variation of generator field current versus generator stator voltage from the minimum achievable generator stator voltage to at least 105 percent of the rated stator voltage with the generator circuit breaker open. For machines with brushless exciters the field current measurement shall be the field current of the exciter.

b. Inertia: A test that reasonably confirms the inertia constant of the turbine-generator.

For example, recording of the rotor speed following opening of the generator circuit breaker with the generator running at a moderate real power output.

c. Synchronous Machine Impedances and Time Constants: Tests that reasonably confirm the d-axis reactances (Xd, X'd, X"d) and time constants (T'do and T"do) of the synchronous generator.

For example, recording of terminal voltage and field current following opening of the generator circuit breaker with the generator running at near-zero real power and under-excited so as to absorb substantial reactive power with the excitation system in manual field voltage control.

2. Excitation Systems

Tests of the excitation system shall be such that they reasonably confirm the characteristics of the voltage regulator and the exciter from dc to 5 Hz. The test recordings shall include generator terminal voltage, field voltage or exciter field current for brushless excitation systems. These tests shall be done with the excitation system in automatic voltage control.

One or more of the following tests can meet the above requirement:

a. VAR Rejection Test: Recording of stator voltage, field voltage (exciter field current for brushless exciters) following opening of the generator circuit breaker with the generator running at near-zero real power and under-excited so as to absorb substantial reactive power.

b. Open Circuit Voltage Reference Step: Recording of stator voltage, field voltage (exciter field current for brushless exciters) following a clearly identifiable step change of voltage regulator reference with the generator circuit breaker open.

c. On-Line Voltage Reference Step: Recording of stator voltage, field voltage (exciter field current for brushless exciters) following a clearly identifiable step change of voltage regulator reference with the generator circuit breaker closed and the generator at normal real power output.

d. Open Circuit Frequency Response Test: Gain and phase angle measurement of stator voltage / voltage reference using a swept sign input from 0.05 Hz to 10 Hz.

3. Power System Stabilizer (PSS)

Tests of the PSS shall be such that they identify the PSS transfer function up to 10 Hz. Approaches for PSS testing are described in *WECC Power System Stabilizer Tuning Guidelines* and *WECC Power System Stabilizer Design and Performance Criteria.*

4. Over-Excitation Limiter (OEL)

Update OEL model data as necessary. Approaches for OEL testing are described in *Guidelines for Over-Excitation Limiter (OEL) and Over-Excitation Protection (OEP) Testing.*

5. Turbine Control

5.1 Hydro Unit

Tests of the governor and turbine shall be such that they reasonably confirm the characteristics from dc to 1 Hz.

The following test is acceptable:
On-Line Speed Reference Step: Recording of generator speed, generator speed reference, gate (valve) position, blade angle if applicable, and generator power following a clearly identifiable step change in speed reference with the generator circuit breaker closed and the generator at normal real power output.

The following measurements should also be made:

a. Measurement of turbine-governor steady-state droop.
b. Measurement of steady-state generator power versus gate position (and blade angle versus gate position for Kaplan turbines) at typical operating heads.

5.2 Steam Turbine Units and Gas Turbine Units

The turbine-governor model should be representative of the actual behavior of the unit the majority of the time. Provide recordings of generator power (resolution of 0.5% or better and 4 second sampling time or shorter) for events including frequency deviations. Sources of the data include, but not limited to, plant DCS, SCADA, digital event recorders. Simulated behavior should reasonably match the recorded data.

The methodology for thermal governor response validation is described in IEEE papers prepared by the members of WECC Governor Modeling Task Force:

1. Les Pereira, John Undrill, Dmitry Kosterev, Donald Davies and Shawn Patterson, “A New Thermal Governor Modeling in WECC,” *IEEE Transactions on Power Systems*, vol.18, no.2, pp.819-829, May 2003.

2. Les Pereira, Dmitry Kosterev, Donald Davies and Shawn Patterson, “New Thermal Governor Model Selection and Validation in the WECC,” *IEEE Transactions on Power Systems*, vol.19, no.1, pp.517-523, February 2004.

A. Introduction

1. Title: WECC Voltage Ride-Through Standard

2. Number: XXX-XXX-XXX-X

3. Purpose: Provide voltage ride-through standards for synchronous and induction generating plants of 10 MVA or more.

4. Applicability
   4.1 Generator Owners
   4.2 Generator Operators

5. Effective Date: ______, 2006

B. Requirements

The following sections describe requirements for both synchronous and induction generating units interconnected at WECC transmission voltages of 60 kV or higher.

B1. Existing and Future Generators Except for Pre-2008 Wind Generators

The following requirements are applicable to existing and future individual generating units at plant sites with an installed capability of 10 MVA or more.[1] Wind generating units operative prior to 2008 or earlier are addressed in Section B2, "Transition Period Wind Generators," and Section B3 "Other Wind Generators."

WR1. Generating units are required to remain in-service as follows:

a) Fault period – During the fault and for a period not to exceed normal clearing times, generating units shall ride through voltage excursions as measured at the high side of plant step-up transformer[2] of 0 per unit volts for 0.15 seconds (9 cycles) increasing to 0.9 per unit volts for 1.75 seconds as shown on Figure 1.

b) Post–fault Period -- Following fault clearing, generating units shall ride through voltage excursions as measured at the high side of the generating plant step-up transformer that are within the voltages and time periods defined in the table below and shown on Figure 2:

---

[1] 20 MVA per FERC Order 661

[2] FERC Order 2003 specifies all measurements would be at the Point of Interconnection. However, FERC Order 661A, which was issued after FERC Order 2003 specifies the point of measurement to be high side of the plant step-up transformer.

Post-Fault Time (Sec)	Voltage ≥ (per unit)	Voltage ≤ (per unit)
0.0	0.50	1.30
0.3		1.30
0.3		1.15
1.0		1.15
1.0		1.10
5.0	0.90	1.10
>5.0	0.90	1.10

WR2. It is not acceptable for generating units to trip except under the following conditions:
- a) For faults that when cleared, effectively disconnect the generating unit from the system.
- b) For clearing times and voltage during faults that exceed the levels indicated on Figure 2.
- c) After the fault period if this action is intended as part of a special protection system.

B2. Transition Period Wind Generators

Transition Period Wind Generators (TPWG) are those wind generating units at generating plants with an installed capacity of 10 MVA or more,[3] are subject to FERC Order 661 (or 661A-check), and have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating units subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

WR3. Generating units are required to remain in-service as follows:
- a) Fault period: During the fault and for a period not to exceed normal clearing times, generating units shall ride through voltage excursions as measured at the high side of plant step-up transformer[4] of 0.15 per unit volts for 0.15 seconds (9 cycles) increasing to 0.9 per unit volts for 1.75 seconds as shown on Figure 3.
- b) Post–fault Period: Refer to Section B1, WR1b.

WR4 It is not acceptable for TPWG generating units to trip except under the following conditions:
- a) For faults that occur between the generator terminals and the POI.

[3] 20 MVA per FERC Order 661

[4] FERC Order 2003 specifies all measurements would be at the Point of Interconnection. However, FERC Order 661A, which was issued after FERC Order 2003 specifies the point of measurement to be high side of the plant step-up transformer.

b) For faults that when cleared effectively disconnect the generating plant from the system.
c) After the fault period if this action is intended as part of a special protection system.
d) For times and voltage excursions that exceed the levels indicated on Figures 2 and 3.

B3. All Other Wind Generators
Wind generating units at generating plants with an installed capacity of 10 MVA or more not covered by Sections B1 and B2 are subject to the following requirements.

WR5. Individual wind generating units that are replaced (for example, wind turbine, anything else ?) are required to meet the requirements described in Section B1, for "Generators other than Transition Period Wind Generators."

C. Measures

WM1. Maintain records of all generator trips and the reason for the trip and report any trips that do not meet this Standard to the Reliability Authority.

WM2. See WM1.

WM3 Maintain records of all TPWG trips reporting any trips that do not meet this Standard.

WM4 See WM3.

WM5. Maintain records of when a TPWG unit is replaced and report any replacement to the Reliability Authority.

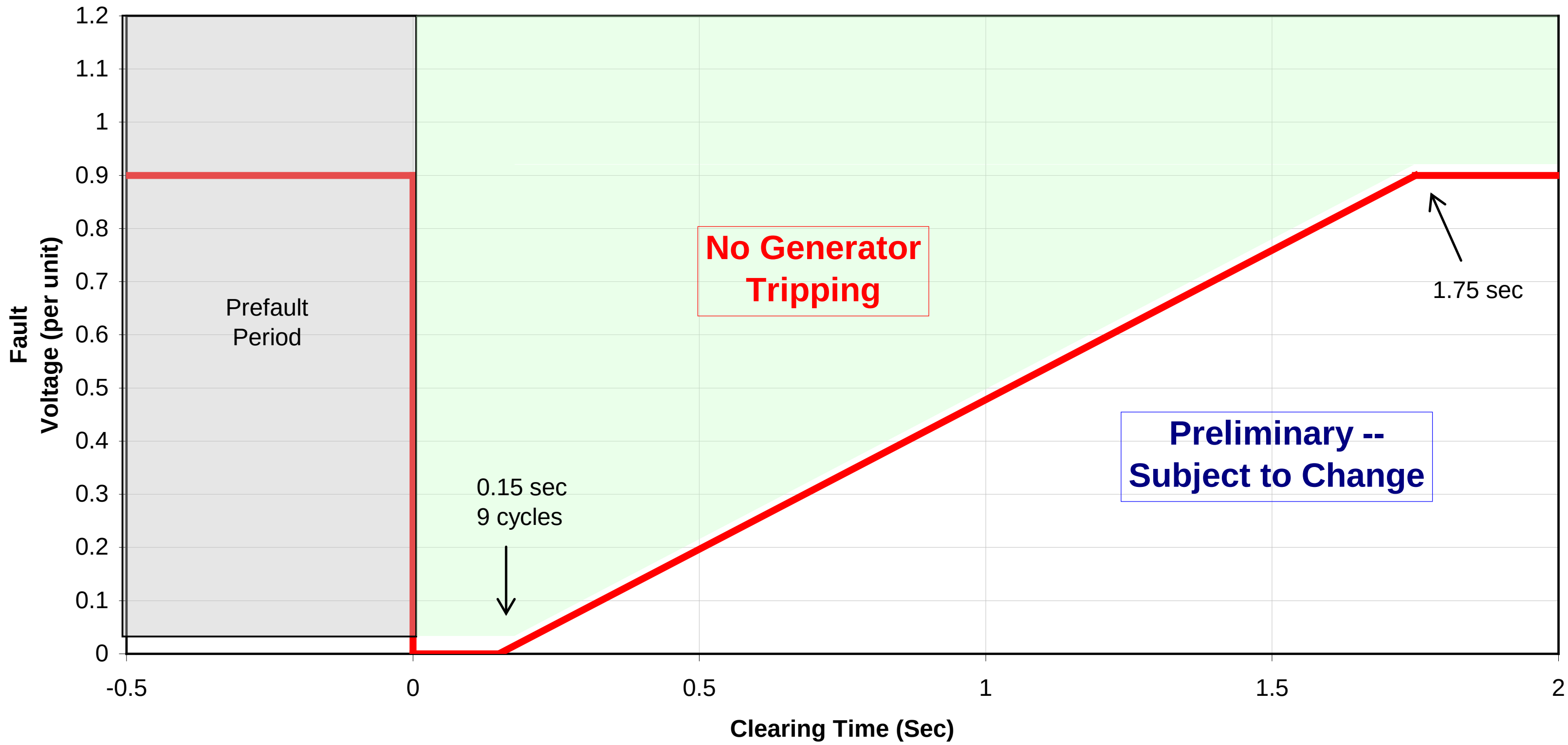
D. Compliance

E. Guides

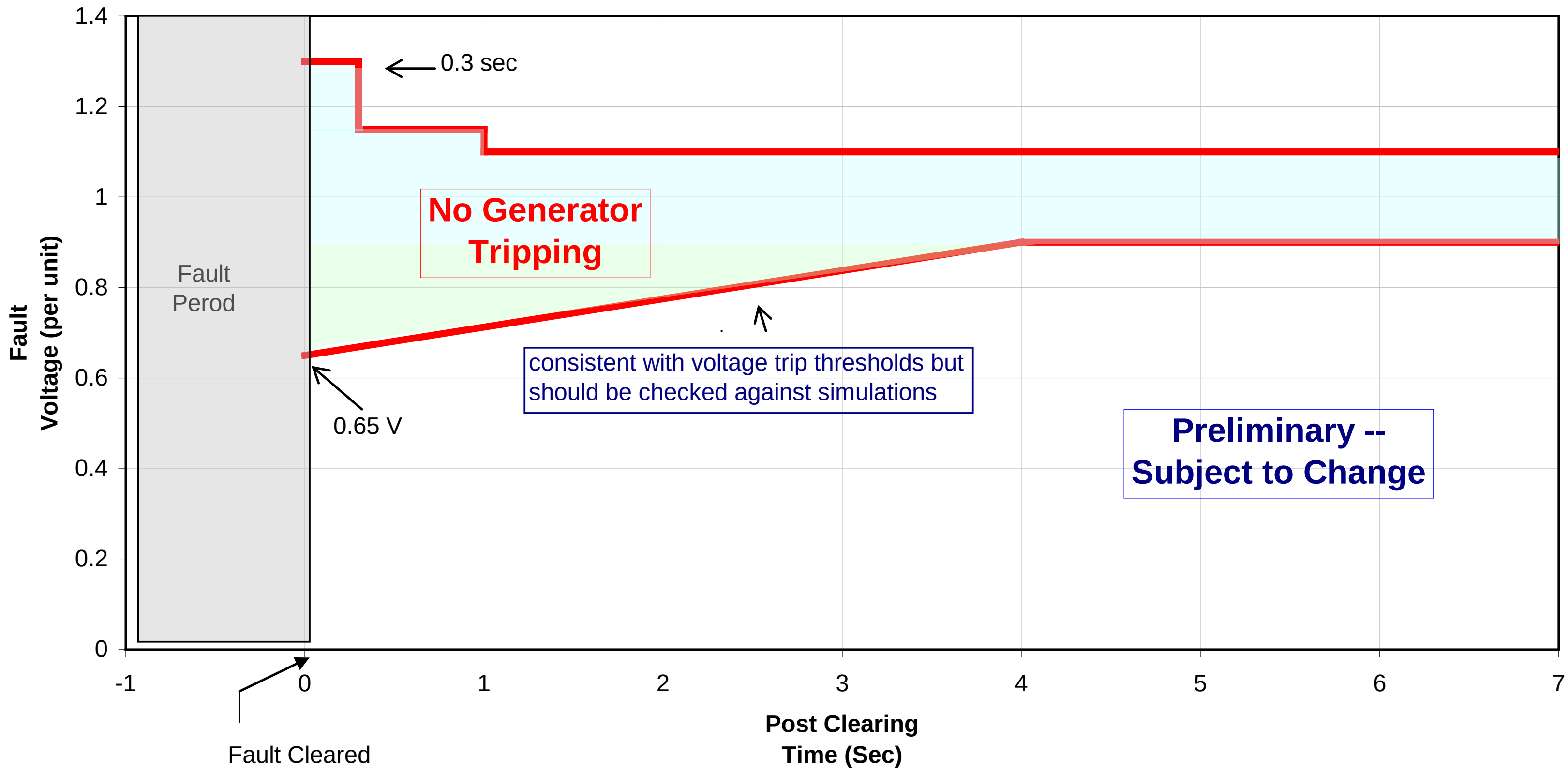
It is acceptable for generating plants subject to this Voltage Ride-Through Standard to meet requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAR Compensator) within the generating plant or by a combination of generator performance and additional equipment.

F. Version History

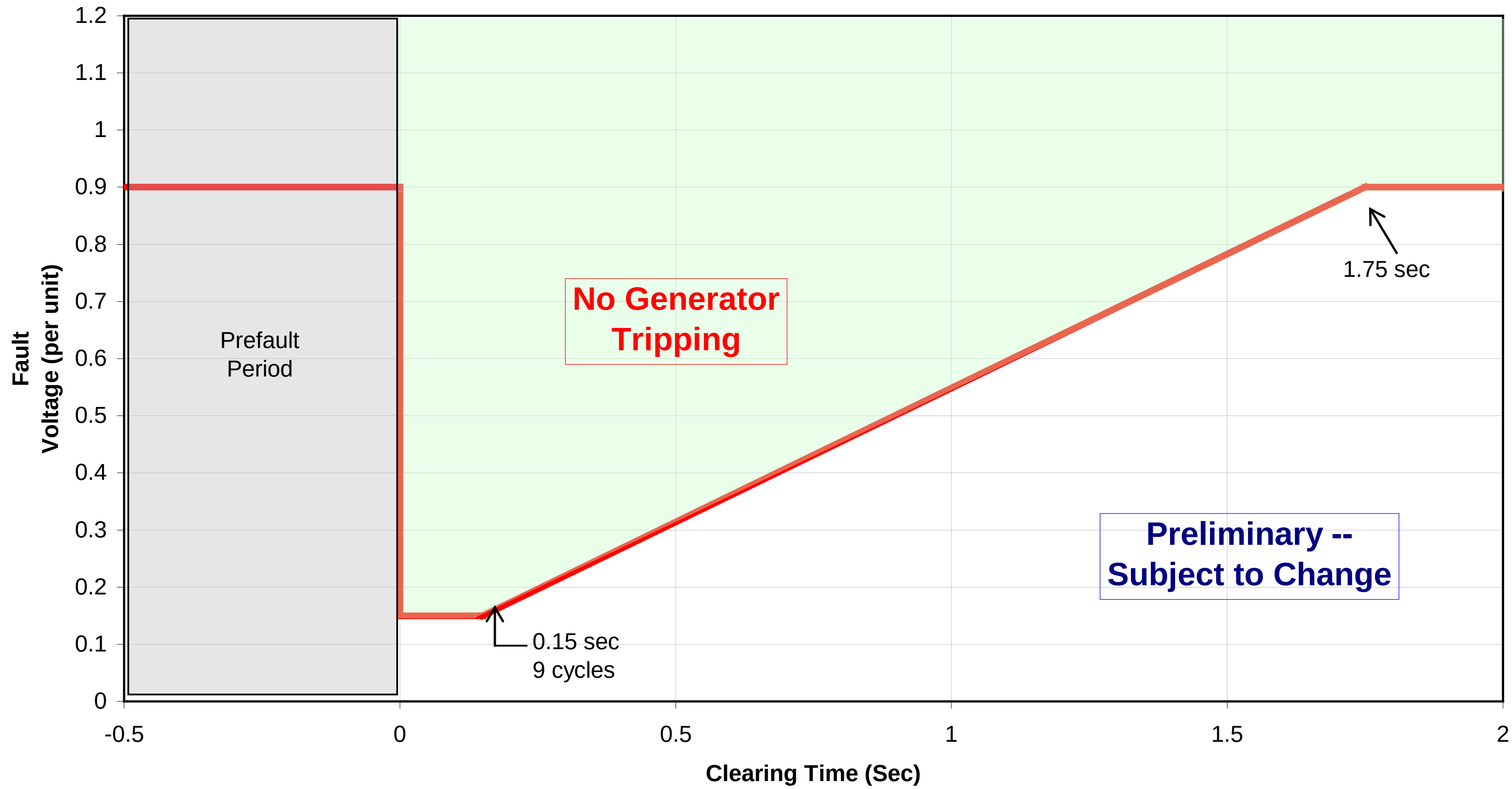
WECC Voltage Ride-Through Standard
Generators other than Pre-2008 Wind Generators
Fault Period
Figure 1



WECC Voltage Ride-Through Standard
Generators other than Transition Period Wind Generators
Post-Fault Period
Figure 2



WECC Voltage Ride-Through Standard
Transition Period Wind Generators
Fault Period
Figure 3



A. Introduction

1. **Title:** **Verification of Models and Data for Generator Excitation System Functions**

2. **Number:** MOD-026-1

3. **Purpose:** To ensure accurate information on generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) is available for models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Date:** To be determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of models and data associated with generator excitation system functions including voltage regulator controls, limiters, compensators, and power system stabilizers. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation describing characteristics of those units that are exempt from a portion or all of these procedures.

R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.3. A list of acceptable models to be used and procedures for revising the list of acceptable models.

~~R1.3.~~R1.4. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.

~~R1.4.~~R1.5. Information to be reported related to generator excitation system functions:

~~R1.4.1.~~R1.5.1. Verified manufacturer and type of excitation system/voltage regulator control system (for example, static, brushless, rotating, etc.).

~~R1.4.2.~~R1.5.2. Verified model from the acceptable model list for each excitation system/voltage regulator control system with associated gains, time constants, and limits.

~~R1.4.3.~~R1.5.3. Verified static set points for under and over excitation limiters.

~~R1.4.4.~~R1.5.4. Verified line drop compensator settings.

~~R1.4.5.~~R1.5.5. Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

~~R1.4.6.~~R1.5.6. Verified model from the acceptable model list for each power system stabilizer with associated gains, time constants, and limits.

~~R1.4.7.~~R1.5.7. Confirmation that the verification was conducted with the voltage regulator in the automatic voltage control mode

~~**R1.4.8.**~~**R1.5.8.** Method of verification used.

~~**R1.4.9.**~~**R1.5.9.** Date of verification.

R2. The Regional Reliability Organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its models and data associated with generator excitation system functions per MOD-026 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for the verification and reporting of models and data associated with its generator excitation system functions in accordance with MOD-026 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure for verification and reporting of generator excitation system data, and any revisions to that procedure were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with its generator excitation system functions, consistent with the Regional Reliability Organization procedure.

A. Introduction

1. **Title:** **Verification of Generator Unit Frequency Response**

2. **Number:** MOD-027-1

3. **Purpose:** To provide verification of generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Date:** To be Determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator unit frequency response. These procedures shall include the following:

R1.1. Response time to be modeled, e.g. up to 30 seconds for steam units, up to 45 seconds for hydro units, etc.

R1.2. Generating unit exemption criteria including documentation describing characteristics of those units that are exempt from a portion or all of these procedures.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.4. A list of acceptable models to be used and procedures for revising the list of acceptable models.

~~R1.4.~~R1.5. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.

~~R1.5.~~R1.6. Information to be reported related to generator unit frequency response:

~~R1.5.1.~~R1.6.1. Verified manufacturer and type of speed governor controls.

~~R1.5.2.~~R1.6.2. Verified model from the acceptable model list for each speed governor control with any associated deadband, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.).

~~R1.5.3.~~R1.6.3. Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response).

~~R1.5.4.~~R1.6.4. Method of verification and conditions of the verification including status of controls.

R2. The Regional Reliability Organization shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying and reporting its generator unit frequency response per MOD-027 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for verifying and reporting generator unit frequency response in accordance with MOD-027 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure, and any revisions to that procedure, for verification and reporting generator unit frequency response was provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with generator unit frequency response, consistent with the Regional Reliability Organization procedure.

WECC Low Voltage Ride Through Standard

This Standard was developed to address reliability concerns associated with un-planned generation tripping resulting from low voltage excursions following disturbances.

New Standard

1. Generators are required to remain in-service during system faults (three phase faults with normal clearing and single line to ground faults with delayed clearing) unless clearing the fault effectively disconnects the generator from the system. This requirement does not apply to faults that would occur between the generator terminals and the high side of the generator step-up transformer or to faults that would result in a voltage lower than 0.15 per unit on the high side of the generator step-up transformer.
2. In the post–fault transient period, generators are required to remain in-service for the low voltage excursions specified in WECC Table W-1 as applied to a load bus. These performance criteria are applied to the generator interconnection point, not the generator terminals.
3. Generators may be tripped after the fault period if this action is intended as part of a special protection system
4. This Standard does not apply to a site where the sum of the installed capabilities of all machines is less than 10MVA, unless it can be proven that reliability concerns exist.
5. This Standard applies to any generation independent of the interconnected voltage level.
6. This Standard can be met by the performance of the generators or by installing additional equipment (e.g., SVC, etc.).
7. Existing individual generator units that are interconnected to the network at the time of the adoption of this Standard are exempt from meeting this Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet this Standard.

WECC Approved Dynamic Model Library

Version 09/06

NOTES:

WECC needs to input the data to the PSLF program, with conversion to the PSS/E program. Therefore, model data must be submitted that can be input to PSLF.

* The PSLF models are converted to these PSS/E models by PTI's conversion program

Acceptable models for the WECC Master Dynamics file (MDF) are highlighted in yellow and indicated in the status column

These models are used in the 06hw3 case and aren't converted, and should be evaluated

EXCITATION SYSTEM MODELS

GE PSLF	PTI PSS/E*	IEEE Standard	Status	Comments	Modifications/Actions Needed	PTI/GE Comments
exac1	EXAC1	AC1A	approved	Brushless AC		Differs from IEEE AC1A -- does not have OEL/UEL inputs and multiplies output by speed.
[esac1a]		AC1A	future	in next PSLF release	New Model	in next PSLF release
exac1a	EXAC1A		approved	exac1 with altered rate feedback source		
exac2	EXAC2		approved	HIR Brushless		Differs from IEEE AC2A -- no OEL/UEL inputs; different field current limit; speed multiplier
esac2a	Not used	AC2A	future	new in GE PSLF	New Model	
exac3	Not used					
exac3a	ESAC3A		approved	GE Alterrex		Differs from IEEE AC3A -- no OEL/UEL inputs; different field current limit; speed multiplier
esac3a	Not used	AC3A	future	new in GE PSLF	New Model	
exac4	EXAC4	AC4A	approved	Some differences from IEEE model		Differs from IEEE AC4A -- no OEL/UEL inputs
[esac4a]		AC4A	future		New Model	in next PSLF release
[esac5a]		AC5A	future	Brushless exciter	New Model	in next PSLF release
exac6a	Not used	AC6A		Alternator, noncontrolled rectifier, lead-lag		Differs from IEEE AC6A -- no OEL/UEL inputs; speed multiplie r
[esac6a]		AC6A	future		New Model	in next PSLF release
esac7b	Not used	AC7B	future	new in GE PSLF	New Model	
exac8b	ESAC8B	AC8B	approved	Brushless exciter with PID voltage regulator i.e. ("SEL" digital excitation system of Basler Electric)		Differs from IEEE AC8B -- no exciter upper limit; added input limits and speed multiplie r
[esac8b]		AC8B	future		New Model	in next PSLF release
exbbc	BBSEX1		approved	Static with ABB regulator		
exdc1	IEEEX1	DC1A	approved	Rotating DC		Differs from IEEE DC1A -- no UEL inputs; speed multiplier
[esdc1a]		DC1A	future		New Model	in next PSLF release
exdc2	EXDC2		approved	Rotating DC with terminal fed pilot, alternate feedback		
exdc2a	EXDC2	DC2A	approved	Rotating DC with terminal fed pilot		Differs from IEEE DC2A -- no UEL inputs; speed multiplier
[esdc2a]		DC2A	future		New Model	in next PSLF release
exdc4	IEEET4	DC3A	approved	Rotating, noncontinuous - minor differences between models		If Kr = 0, should convert to IEEEX4 (IEEE DC3A).
[esdc3a]		DC3A	future		New Model	in next PSLF release
[esdc4b]		DC4B	future	Rotating DC with PID	New Model	in next PSLF release
exeli	EXELI		approved	Static PI transformer fed excitation system		
exst1	EXST1	ST1A	approved	Static with double lead/lag		Differs from IEEE ST1A -- no OEL/UEL inputs; added Xe Ifd loading; RFB before field current limiter.
[esst1a]		ST1A	future		New Model	in next PSLF release
exst2	EXST2	ST2	approved	SCPT - lead/lag block (Tc, Tb) added		
exst2a	ESST2A	ST2A	approved	lead/lag block (Tc, Tb) is included to match the WECC FM		Differs from IEEE ST2A -- no UEL inputs; added lead/lag.
[esst2a]		ST2A	future		New Model	in next PSLF release
exst3	EXST3	ST3	approved			
exst3a	ESST3A	ST3A	approved	Use this model for GE Generex		Differs from IEEE ST2A -- no UEL inputs; fewer time constants.
[esst3a]		ST3A	future		New Model	in next PSLF release
exst4b	ESST4B	ST4B	approved	GE EX2000 bus fed potential source, static compound and Generrex-PPS or -CPS, and SILCOmatic 5 excitation systems, with proportional plus integral (PI) voltage controller		Differs from IEEE ST2A -- no OEL/UEL inputs
[esst4b]		ST4B	future		New Model	in next PSLF release
[esst5b]		ST5B	future	Variation of ST1A (New IEEE Model)	New Model	in next PSLF release
[esst6b]		ST6B	future	Variation of ST4B with field current limit (New IEEE model)	New Model	in next PSLF release
[esst7b]		ST7B	future	Static with limiters (Alstom) (New IEEE model)	New Model	in next PSLF release
exwtg1	Not converted (1)			Excitation system model for wound-rotor induction wind-turbine generator	replace with new wind models	We need details of this model This is crude Vestas V80 model. This will be obsolete after generic Type 2 model is available.
exwtge	Not used			Excitation (converter) control model for GE wind-turbine generators	replace with new wind models	
ieeet1	IEEET1		approved	Old type 1		
mexs	Not used			Manual excitation control with field circuit resistance		
pfqrg	Not used			Power factor / Reactive power regulator		
rexs	REXSYS		approved	General Purpose Rotating Excitation System Model		
scrx	SCRX		approved	intended for use where negative field current may be a problem		
sexs	Not used			for use where details of the actual excitation system are unknown and/or unspecified		PSS/E has a SEXS (simplified excitation system) model (which is similar to the PSLF sexs model but without the PI control block)

texs	Not converted (9)			Transformer Fed Excitation System Model	replace with esst6b	we don't convert this. Per our notes from previous M&V mettings, this model was not to be used in WECC.
oel1	Not converted (277)			Over excitation limiter	Use new model	Please note that this is not an IEEE standard model. GE developed this model for WECC use. If we have to provide a corresponding PSS/E model, we have to get the block diagram from GE This should be replaced by IEEE model.
[oel]		OEL	future	New IEEE model	New Model	in next PSLF release
[uel1]		UEL1	future	New IEEE model	New Model	in next PSLF release
[uel2]		UEL2	future	New IEEE model	New Model	in next PSLF release

GENERATOR MODELS

GE PSLF	PTI PSS/E*	IEEE Standard	Status	Comments	Modifications/Actions Needed	PTI/GE Comments
gentpf	GENROU/IEEEVC		approved	WECC Model		
genrou	GENROU/IEEEVC		approved	Round rotor generator model, use for thermal generator models		
gensal	GENSAL/IEEEVC		approved	Salient pole generator model, Use for Hydro generator models		
gencc	GENROU/IEEEVC		approved	Cross Compound generator model		
genwri	not converted (1)			Vestas Wind turbine generator, 1 instance in 08HS3 base case	will be replaced with new wind models	We need details of this model This will be replaced by generic Type 2 WTG generator model.
gewtg	not used			GE Wind turbine generator	will be replaced with new wind models	We can convert this
motor1	CIMTR4		approved	Used for wind		
gencls	not used			Used to force a signal, or classical generator model		We have a GENCLS model. The PSLF model gencls does get converted to the PSS/E model GENCLS. [Forcing signal (playback) feature not needed in library datasets.]

PSS MODELS

GE PSLF	PTI PSS/E*	IEEE Standard	Status	Comments	Modifications/Actions Needed	PTI/GE Comments
wsccst	ST2CUT		approved	Dual input PSS		
pss2a	PSS2A	PSS2A, PSS3B	approved	Dual input PSS (2A is delta P-omega, 3A is Accelerating power (Unitrol))	extra lead/lag block	
ieeest	IEEEST	PSS1A	approved	Single input PSS, dual lead lag		
psssb	PSS2A	PSS2A, PSS3B	approved	pss2a + transient stabilizer		
[pss1a]		PSS1A				in next PSLF release
[pss2b]		PSS2B		Extra lead/lag (or rate) block added at end (up to 4 lead/lags total)		in next PSLF release
[pss3b]		PSS3B				in next PSLF release
[pss4b]		PSS4B		ABB multi-band		in next PSLF release
[psssh]				Siemens H infinity PSS		in next PSLF release

LOAD MODELS

GE PSLF	PTI PSS/E*	IEEE Standard	Status	Comments	Modifications/Actions Needed	PTI/GE Comments
alwscc	IEELAR		approved	Area load model		
blwscc	IEELBL		approved	Bus load model		
motorw	CIMWBL		approved	Induction Motor Model		

TURBINE/GOVERNOR MODELS

GE PSLF	PTI PSS/E*	IEEE Standard	Status	Comments	Modifications/Actions Needed	PTI/GE Comments
g2wscc	WSHYDD		approved			
gast	URGS3T		approved			
ggov1	GGOV1		approved			
gpwscc	WSHYGP		approved			
hyg3	WSHYGP		approved		Check WSHYGP conversion	
hygov	HYGOV		approved			
hygov4	IEEEG3		approved		Need new acceptable model in PTI	
ieeeg1	WSIEG1		approved			
ieeeg3	IEEEG3		approved			
lcfb1	ULCFB1		approved			
pidgov	PIDGOV		approved			

tgov1	TGOV1		approved			
ggov2	new		future	new in GE PSLF		We have the new GGOV2 model in a user written format. We will see if this can be given to users as a user model in the next point release. We hope to make it a standard model for the next major release.

OTHER MODELS

GE PSLF	PTI PSS/E*	IEEE Standard	Status	Comments	Modifications/Actions Needed	PTI/GE Comments
colatr	not converted (1)			Colstrip ATR relay		was developed for WECC. We don't have a PSS/E model for this, need details
dc4t	not converted (2)			old PDCI DC model		We have this model, but guess this old model will become obsolete Removed from PSLF.
dcmt	new		approved	new PDCI DC model		We have just developed two new models (north to south and south to north) for the PDCI. GE needs details for data conversion to PSLF.
epcdc	CDC6		approved	Intermountain DC model		
fmeta	not converted (1)			Frequency meter, whole system or bus		not converted for the same reason that vmeta is not converted (please see below)
gp1	not converted (4)			Generator Protection relay		We don't have a PSS/E model for this, need details
lsdt1	LDS3BL		approved	Underfrequency relay		
lsdt2	LVS3BL		approved	Undervoltage relay		
lsdt9	LDS3BL		approved	Underfrequency relay		
monit	not converted (1)			solution monitor		not converted for the same reason that vmeta is not converted (please see below)
ooslen	not converted (11)			3 zone out of step relay	low priority	We don't convert this. The reason is not because we don't have a model. PSS/E has a double circle or lens out-of step line relay model called 'CIROS1' (please note that like any other relay model, this also is a generic line-relay model not representing any particular manufacturer). The reason that the data is not converted is probably because the data requirements of the PSLF 'ooslen' model do not match the data requirements of the PSS/E 'CIROS1' model. However, this does not prevent the PSS/E users to create a DYR data record and include the CIROS1 model for every occurrence of the PSLF 'ooslen' model.
[scmov]				Series capacitor MOV and bypass model		in next PSLF release
stcon	not converted (2)			Static synchronous condensor		We don't convert this. This model, per our notes from the previous M&V mettings, was not to be used in WECC. This also is a generic model not representing any particular manufacturer. PSS/E also has two generic static condenser models - the CSTATT (use of this requires a generator model in load flow), and the CSTCNT (use of this requires a FACTS device model in load flow). We can not convert the PSLF STCON to PSS/E CSTATT or the CSTCNT models because the data requirements are different.
svcwsc	CSVGN5, CSVGN6		approved	Static Var Source model		
tlin1	not converted (114)			under frequency or under voltage line relay	Investigate better method for pump (Generator) tripping	We don't convert this, because PSS/E does not have the under frequency or under voltage line relay model. Our consulting group has a user written model and we can include it in PSS/E. We will add this in our list of task to do. As an interim solution we can check if we can make this available as a user written model before it becomes a PSS/E standard model. However, given the fact that this also is a generic model, the data requirements of the PSLF 'tlin1' may not match the data requirements of the PSS/E model, and hence we may not be able to convert from the PSLF to the correspinding PSS/E model. Nonetheless, a model can be made avialable for WECC PSS/E users.
vmeta	not converted (2)			Voltage meter, whole system or bus		We have this model, but don't (and can not convert) it. The reason the conversion is not possible is because the corresponding PSS/E model does not have to be entered into the PSS/E dynamics raw data file (the DYR file). In PSS/E, using the GUI we select CHSBNEW to place the subsystem (which could be on the basis of bus, area, owner or zone) voltages in the output channel.
vwscc	CSVGN5		approved	Static Var Source model		

WECC Field Test Report regarding
MOD-026 - Verification of Models and Data for Generator Excitation System Functions
MOD-027 - Verification of Generator Unit Frequency Response
PRC-019 - Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

I - Background

WECC generator model data validation requirements were initially put in place following the July and August 1996 disturbances on the western interconnection. These disturbances provided a disturbing indication that the WECC dynamics models provided an overly optimistic view of system performance. At that time WECC initiated an extensive effort to initiate generator testing and data validation. Test guidelines were written, and testing and data requirements developed on a fast track and put in place during 1997. Several workshops were planned and implemented to inform generator owners regarding the new data validation requirements. Today approximately 80% of the generators required to validate their data (generators larger than 10 MW) in WECC have met those requirements on a voluntary basis.

Despite the initial validation efforts, WECC system modelers noted that the model still did not match the frequency response in the western system, so another effort was initiated to focus on frequency response modeling. As a result, new governor and load controller models were added to the major programs, and new model data verification methods were developed that focus on frequency response modeling. There was again a large effort to train generator owners in how to obtain the needed frequency response information and populate the newly developed models.

During the most recent few years, WECC modelers have updated the generator test and model validation requirements based upon the experiences with the initial requirements, and a new Generator test policy was approved in WECC during 2006. These new documents focus on model functional and validation requirements, while providing flexibility on how those requirements are met. For example, they provide for additional flexibility with regard to use of Disturbance Monitoring data to validate generator models.

The policy developed as a result of these efforts and associated documents are accessible to the public on the WECC web site at the following link:

http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewdownload&cid=1

These documents were developed by the WECC Modeling and Validation Work Group and the WECC Controls Work Group, and have been approved through the WECC Committee structure and by the WECC Board of Directors during July of 2006.

Upon review of the WECC documents for this field test, the WECC Generator Test Policy requirements are found to meet the RRO requirements of MOD-026, MOD-027, and PRC-019 that are being field tested here. Additionally, approximately 80% of the generators in WECC have conducted initial testing under the existing WECC Generator test policy and its predecessor, and have thus met this field test requirement.

The WECC generator test policy was applied for several years and then was updated based upon the experiences of those that tested the generators under the initial requirement. Hence, the field test in WECC has been very thorough.

Recent validation efforts comparing disturbance monitor measurements to system model results indicate that current WECC model results track actual system response much better in more recent disturbances than before 1996. Continuing efforts are being made focused on load modeling to further improve system models.

II - Executive Summary of Field Test Results

The following current WECC documents meet the RRO requirements of the field test versions of MOD-026, MOD-027, and PRC-019. The WECC Generator Model Validation requirements and data requirements are gathered into one WECC policy and its accompanying attachments as follows:

WECC Generating Unit Model Validation Policy
This document succinctly states the WECC generator model validation and data submittal policies. It defines the responsibility of the Generator Owner, the Transmission Planner, and the RRO relative to testing and validating the generator model and processing model data. It defines which generators are required to be tested, and provides requirements regarding the timing under which validation and submittal of data for new or modified generator equipment must be performed. It requires an initial baseline test. It also requires a 5 year revalidation of generator data. It also provides a statement regarding the exemption policy. The Policy references the following documents for specific aspects of the requirement.

Generating Facility Data Requirements
This document details the data that are required for the generating facility. An important aspect is that it requires that target models for the data are found on a list of WECC Approved Models. This document requires certain information additional to the data targeted for the models in a dynamic stability program and

includes information such as nameplate information, type, and manufacturer for the various components. It includes a requirement for a one-line diagram, reactive capability curves, step-up transformer data, and a description of any load controller actions.

Generating Unit Baseline Test Requirements

This document provides guidance regarding how to comply with the policy baseline test requirement. Generator owners are required to test the generating unit and validate its model data. This document lists the items that must be verified through tests. However, it does not spell out how the test must be conducted, leaving that up to the expert tester. For example, under "Inertia" it says "A test that reasonably confirms the inertia constant of the turbine-generator." Then it provides an example of how the inertia constant can be confirmed. It also provides references to other documents that detail possible test methods, such as WECC's 1997 Generator Test requirement and other information that can be found on the WECC web site.

Generating Facility Model Validation Requirements

This documents details model validation requirements as required every 5 years. This is another innovation that arose from experience with WECC's 1997 Generator Test requirement and provides options for validating generator model data by comparison of model results to measurements from a performance monitor installed near the machine's terminals rather than requiring redoing the baseline tests every five years.

List of WECC-Approved Models

This is an important component of the WECC Policy, and was added to the WECC requirement as a direct result of experience with the 1997 WECC generator test policy. WECC found that data provided needed to specifically target models available in the commonly used dynamic stability programs. Since WECC

Members use the GE PSLF program and the PTI PSS/E program, the models used must be available in both programs. User defined models are problematic, and WECC is making efforts to correct perceived modeling deficiencies by making sure needed models are available to the industry (for example, there is an ongoing effort to develop standard wind models).

As mentioned in the background material, these documents meet the requirements of MOD-026, MOD-027, and PRC-019, and were approved by the WECC Board during July of 2006. Approximately 80% of the WECC generators have been tested under the WECC 1997 Generator Test Requirement, and lessons learned have been applied in the new 2006 WECC Generating Unit Model Validation Policy. The new policy spells out in more detail the responsibilities of the various parties, and provides more flexibility to experts to determine how to meet the requirements. In addition, the new policy has been applied directly during the validation/revalidation of data for several generators of all types.

As a result of the massive generator testing effort in WECC since 1996, including efforts to improve governor, wind, and load modeling, WECC models are significantly better today than during 1996. Improvements in WECC system models have been confirmed by comparing measurements from performance monitors to simulation results. There are significant ongoing efforts in wind generator modeling and load modeling to further improve system models.

It is very important that model results match system performance. Transfer capabilities are based upon results from system models, and if models are overly pessimistic, the system is not fully utilized, while using the results of system studies using overly optimistic models can be catastrophic. System disturbances are costly and dangerous. There have also been side benefits from the required generator testing through having independent experts review generator plant performance and operating procedures. For example, in some instances equipment problems have been discovered that could have resulted in costly generator outages had they not been detected. As a result of what was learned regarding plant frequency response, not only was the model improved but WECC was able to initiate discussions regarding possible new performance requirements.

WECC has had a generator test policy since 1997. The purpose of the updated 2006 policy is to provide clarification regarding responsibilities and requirements and to providing additional options for meeting the data needs (particularly of the revalidation requirement) rather than to add additional requirements. Thus, WECC has essentially been field testing the generator baseline test requirements since 1997. WECC and a majority of its Members are convinced that the generator testing requirements are important, and that the costs, although significant, are necessary.

WECC has established an implementation plan, which basically requires that those that have not yet met the WECC generator baseline test requirement (which has been a requirement since 1997) provide a schedule for when they plan to meet it. The implementation plan indicates that generators that have not met the baseline test requirement continue to be non-compliant until the tests are performed. The implementation plan also requests a schedule for completing the five-year revalidation requirement from those that met the baseline requirement. Those that have met the initial WECC requirement are rewarded in that they will continue to be considered compliant with the WECC generator test requirement until five years from December 31 2006, although some of the units were baseline tested as early as 1996. This helps maintain a distribution of revalidation dates throughout the five year period. There are limited organizations/individuals qualified to perform the validation testing, and the requirement must allow for them to manage their workload.

There are two suggestions for changes to the draft NERC Standards. WECC recommends that MOD-026 and MOD-027 be revised with regard to the generating unit exemption criteria in R1.2 to clarify that documentation of exempt units should describe the characteristics of the exempt units, and to clarify that it doesn't need to require a list of all of the exempt units. The requirements should also be revised by adding a requirement that there be a list of acceptable models and a procedure for updating the list of acceptable models. Mark-ups of the standards are attached.

III – Details/Appendices/Attachments

The following links to the area on the WECC web site where the WECC generator test documents may be found

.

http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewdownload&cid=1

Additionally the WECC generator test policy is attached, along with referenced requirements documents.

Documents are attached that provide a red-line of the NERC MOD-026 and MOD-027 standards with suggested revisions.

A detailed explanation of how each of the field test standards is met by the WECC Generator test policy is also attached.

WECC Field Test Report regarding PRC-024 - Generator Performance During Frequency and Voltage Excursions

I - Background

WECC requirements regarding off-nominal frequency performance of generators are included in the document "*WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements*."

For this field test, WECC reviewed the WECC requirements in the above document relative to the field test standard PRC024 and found that the requirements in the above referenced document meet the RRO frequency requirements of the NERC field test standard PRC-024.

The WECC off-nominal frequency plan was developed by a task force under the WECC TSS in 1997 and has been updated multiple times since then. In particular, the generator frequency requirements were updated based upon manufacturer input to better fit the frequency deviation capabilities of current equipment. The frequency requirements were developed under the WECC Technical Studies Subcommittee (TSS), and approved by TSS and the WECC Planning Coordination Committee. The WECC Board approved the most recent changes to the requirements during December 2003.

WECC approved a plan regarding voltage performance of generators titled "*WECC Low Voltage Ride Through Standard*" a few years ago, but after FERC and NERC revised some requirements, an effort was initiated to revise the WECC voltage requirements. WECC requirements regarding voltage performance of generators are still under development, and efforts are being made to coordinate the WECC requirements development efforts with ongoing FERC and NERC standards development efforts.

II - Executive Summary of Field Test Results

The following current WECC documents meet the RRO requirements of the field test version of PRC-024.

WECC *Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements*
This document provides for coordination of off-nominal frequency load shedding with allowable frequency/time delays for generators. The WECC off-nominal frequency plan provides minimum requirements. Each major region of WECC has chosen to have regional requirements that trip more load sooner than the minimum requirements plan. Generators are allowed exceptions to trip at higher frequencies/smaller time delays than allowed under the WECC plan only if they arrange for compensating load tripping.

WECC *Low Voltage Ride Through Standard*
This WECC Policy document will be replaced as a new standard is developed. This document identifies voltage levels and conditions under which a generator should remain connected to the system.

The *WECC Reliability Criteria* include the *NERC/WECC Planning Standards* and the *Minimum Operating Reliability Criteria*
These WECC documents include the voltage/time duration table W-1 referenced by the voltage requirements and also require Coordination of generator protection, including back-up protection, with transmission Protection Systems

July 12, 2006 Draft *WECC Voltage Ride-Through Standard*
This document is a draft and is only provided as a sample of what WECC envisions. Efforts will be made to match FERC and NERC requirements.

Further discussions may be needed to address exemptions and variances as specified in the NERC field test standard PRC-024. Otherwise, the listed current and draft WECC requirements meet the RRO requirements of the NERC field test standard PRC-024.

III – Details/Appendices/Attachments

A detailed explanation of how each of the field test standard requirements is met by the WECC policies is attached. The attached compares all four field test standards, PRC-024 is the last standard compared.

The WECC *Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements* can be obtained from the WECC web site by clicking on the following link: http://www.wecc.biz/documents/library/procedures/planning/WECC_ONF_Report_July_2005.pdf

The WECC *Low Voltage Ride Through Standard* is attached.

The *WECC Reliability Criteria* include the *NERC/WECC Planning Standards* and the *Minimum Operating Reliability Criteria* are available at the following link:

http://www.wecc.biz/documents/library/procedures/CriteriaMaster.pdf

The July 12, 2006 Draft *WECC Voltage Ride-Through Standard* is attached. This document is a draft and is only provided as a sample of what WECC envisions.

WECC Field Test of NERC draft Standards MOD-026, MOD-027, PRC-019, and PRC-024

Presented June 18, 2007

1996 Outages

- During July and August of 1996 System Disturbances Occurred
- Dynamic Simulations indicated the system would be stable
- Initiated a significant effort to improve the WECC System Models

Initiatives to Improve Models

- Generator Testing Program
- Load Model Improvements
  - Induction Motor Models
- Governor Model Improvements
- Extreme Disturbance Policy
  - NE/SE Separation Scheme
  - Reevaluate Underfreqency Load Shedding Programs

Field Testing

- Compared WECC Policies with the requirements of the field tested standards,
- Found that WECC Policies had already been developed, many as a result of the 1996 Disturbances that met most of the field test requirements

WECC Generator Testing

- Started in 1996
  - Reactive Test Requirement
  - Dynamic Data Validation Requirement
  - Certificates Issued to those meeting requirements
  - Approximately 80% (1340/1686) of the Generators Larger than 10 MW in WECC have been tested. Major Effort
  - Several have been retested (5 year requirement)
- New Policy Approved During 2006
  - Based on Experience with 1997 Policy

2006 Generator Test Policy

- Improvements
  - List of approved models –
    - Found in both major programs in use in WECC
    - User defined models and proprietary models are problematic
      - Must be able to share models freely to study the system
  - Clearly Assigned Responsibilities
    - Generator Owner Responsible for Tests
    - Transmission Planner Responsible for tracking completion of tests and reviewing results for connected generators

2006 Generator Test Policy

- Improvements (Continued)
  - Allow flexibility re procedures to provide validation
  - Performance based requirements,
  - Initial Baseline test and Data requirements
  - Option to perform data validation using performance validation equipment

2006 Generator Test Policy

- Components
  - *WECC Generating Unit Model Validation Policy*
    - This document succinctly states the WECC generator model validation and data submittal policies.
  - *Generating Facility Data Requirements*
    - This document details the data that are required for the generating facility.

2006 Generator Test Policy

- Components
  - *Generating Unit Baseline Test Requirements*
    - Guidance regarding how to comply with the policy baseline test requirement.
    - Generator owners are required to test the generating unit and validate its model data.
    - List of items that must be verified through tests.
    - Does not spell out how the test must be conducted, leaving that up to the expert tester.
      - Ie. “A test that reasonably confirms the inertia constant of the turbine-generator”
      - Also provides guidance regarding test options.

2006 Generator Test Policy

- Components
  – *Generating Facility Model Validation Requirements*
    - Details model validation requirements as required every 5 years.
    - Provides the option for validating generator model data by comparison of model results to measurements from a performance monitor

2006 Generator Test Policy

- Components
  - *List of WECC-Approved Models*
  - Needed ongoing model development efforts
    - Load Models
    - Wind Models

Governor Model Development

- Found that the model had about half the frequency dip of system disturbances
  - Needed some new improved models in the programs
  - Plant frequency control
  - Model unresponsive governors properly
- Verify governor model response with "good" SCADA data.
- Review multiple disturbances, variability

Off-nominal Frequency Policy

- Requirements include coordinated load and generator off-nominal requirements.

Recommendation for SAR

- Division of Six standards seems strange
  - Generator Testing Standard, cover verification of the entire generator model.
  - What about generator impedances, time constants, inertia, etc.
- Coordination of Relays (test?)

Recommendations re draft standards

- Clarify that documentation of exempt units should describe the characteristics of the exempt units,
- Clarify that it doesn’t need to require a list of all of the exempt units.
- There should be a list of acceptable models and a procedure for updating the list of acceptable models.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

April 20, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Periods Open

The Standards Committee (SC) announces the following standards action:

SAR for Generator Verification (Project 2007-09) Posted for 30-day Comment Period April 20–May 21, 2007

The SAR for Project 2007-09 proposes completing the following four Phase III & IV standards that have been field tested but require additional modifications beyond the scope of their original SAR:

- PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024 — Generator Performance During Frequency and Voltage Excursions
- MOD-026 — Verification of Models and Data for Generator Excitation System Functions
- MOD-027 — Verification of Generator Unit Frequency Response

The SAR also involves revising the following two already-approved Phase III & IV standards:

- MOD-024 — Verification of Generator Gross and Net Real Power Capability
- MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

The modifications will address issues raised by FERC and stakeholders about these standards, and will bring the standards into conformance with the ERO Sanctions Guidelines and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR.

SAR for Permanent Changes to the Timing Table in the Coordinate Interchange Standards (Project 2007-14) Posted for 30-day Comment Period April 20–May 21, 2007

An Urgent Action SAR to modify the Timing Table in some of the Coordinate Interchange standards (INT-005, INT-006, and INT-008) was approved by its ballot pool on March 30, 2007. The Urgent Action SAR made modifications to the timing table so that the reliability assessment period for WECC was lengthened from 5 minutes to 10 minutes for e-tags submitted less than 1 hour and greater than 20 minutes prior to ramp start.

The new SAR for Permanent Changes to the Coordinate Interchange Table proposes to make the above changes permanent and also proposes to add the following to the timing table to bring the timing table into alignment with the categories (On-time, Late, After-the-Fact, and Pre-late) used in the latest E-Tag Specification with respect to receipt of an arranged interchange.

- Designation of request status based on start and submittal times
- Assess times for After-the-Fact requests
- WECC pre-schedule late (Pre-late) submittal definition

Please use the comment form to provide comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
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<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
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</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☐ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,

   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and

   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments:

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments:

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Thad K. Ness	
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Telephone:	614-716-2053	
E-mail:	tkness@aep.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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Additional Member Name	Additional Member Organization	Region*	Segment*

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PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

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You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments:

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can “reduce” but cannot “expand” this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments: None

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments: None

7. If you have any other comments on this SAR that you haven’t already mentioned above, please provide them here:

   Comments: Please transmit to the Standard Drafting Team the following specific suggested revisions to MOD-025:
   Key changes relate to FERC's requirement that regional "fill-in-the-blank" standards be rewritten as North American standards; these and other recommended changes are provided below:

   A. Introduction

   1. Title:Verification of Generator [ ] Reactive Power Capabilities

   3. Purpose: To ensure that [ ] steady-state models used for assessing Bulk Electric System reliability reflect realistic/usable generator reactive power capabilities.

   B. Requirements

R1. The North American Electric Reliability Corporation (NERC) shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.5. Information to be reported to Regional Reliability Organization (RRO):

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1. and at Minimum Real Power output levels of generators. Net capabilities should be reported at the low- and high-voltage terminals of generator step-up (GSU) transformers.

R1.5.3. Verified Real and Reactive Power of auxiliary loads fed from: (a) generator bus, and (b) transmission system bus (listed separately).

R1.5.5. System bus voltages (as scheduled and as verified), generator bus voltage and generator hydrogen pressure.

R1.5.6. In-service transformer tap setting and impedance (including base quantities).

R1.6. Requirement that sanity checks (or analysis) be used to ensure consistency/accuracy of reactive power capabilities obtained via measurement.

R2. The RRO shall provide [ ] generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to ...

R3. The Generator Owner shall follow NERC's procedures for verifying and reporting to RRO generator gross and net Reactive Power capabilities per R1.

C. Measures

M2. The RRO shall have written evidence that [ ] procedures...

M3. The Generator Owner shall have written evidence it provided verified information of its generator gross and net Reactive Power capabilities, consistent with NERC's procedures.

D. Compliance

This section should be revised to recognize that the procedures for generator Reactive Power capability verification will be written by NERC as a continent-wide standard. AEP recommends that AEP's Circular Letter OP-G-CL-011 (Reactive Capability Testing of Generators), developed over nearly two decades of testing experience and advocacy within the former ECAR region, be used as a reference in drafting this standard.

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	John E. Sullivan
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E-mail:	JSullivan@ameren.com

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

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Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Background Information

The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments: With regards to the scope of MOD-025, it should not be necessary to include a blanket requirement for verification of reactive power capability at multiple points for all generators. However, should a generator frequently have difficulty reaching its stated reactive power output, additional testing requirements for that generator would be indicated.

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,

- Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
- Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments:

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: MOD-026-1 and MOD-027-1: The existing language in R1.2 for each of these standards states that manufacturer data is one of the methods which can be utilized for verification of models and data. However, typical data for these types of models is generally not adequate to sufficiently characterize the models for use in system simulations.

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<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: Robert Ferguson</td></tr>
<tr><td colspan="3">Organization: Amerren Services</td></tr>
<tr><td colspan="3">Telephone: 314-554-2944</td></tr>
<tr><td colspan="3">E-mail: RFerguson</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☒ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
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<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
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<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail: I

Additional Member Name	Additional Member Organization	Region*	Segment*
	.		
	.		

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

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You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments: At this point in time we cannot determine if there is a reliability related need to finalize these standards. The results of the field test by the 4 participating RROs will not be complete until late June 2007. The 4 RROs, in support of the NERC Field Test team, have spent significant resources in an attempt to implement procedures and subsequently carry out the draft Reliablity Standard requirements. Thus, in order to ensure proper consideration is given to the results of the field tests, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test. Recommend that the last sentence in the paragraph in the SAR on page SAR-3 under "Detailed Description" be modified to: "In addition, the SDT will consider and address all applicable FERC Orders, including Order 693, in addition to any modifications, deficiencies, and other items as found in the NERC Phase III-IV Planning Standard Field Tests, and in addition the following porposed changes for each of the six standards in this set of standards:"

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
   - Addressing issues identified in FERC Order 693.

   Do you agree with this scope? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: The scope of MOD-025 has been expanded beyond what is stated above. The changes to the four field test standards should be based on the field test results.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments:

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance: none
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice: none
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Comments: The scope of MOD-024 and MOD-025 should not be expanded beyond the scope contained in the current version of these two standards. The results of the field test for the other 4 Draft Reliability Standards by the 4 participating RROs will not be complete until late June 2007. Thus, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Rich Young	
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Telephone:	262-506-6825	
E-mail:	ryoung@atcllc.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

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You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
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   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

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   ☒ Yes

   ☐ No

   Comments:

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   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments:

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   ☐ Yes

   ☒ No

   Comments: Generator Operator should be included.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

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   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven’t already mentioned above, please provide them here:

   Comments: The SAR includes language requiring the SDT to identify any generators that should be exempt from compliance. There are many standards both under this project and others (such as Project 2007-01) that need to consider applicability based on generator size and/or voltage. If these standards remain separate, this requirement will either force needless repetition of the same language in many standards, or there is a distinct possibility that differences will develop among the exemptions, making it very difficult for generator owners to know which of their generators are covered by which standards. I suggest there should be a global definition of minimum generator size to which all NERC Reliability Standards apply, much like the global definition of Bulk Electric System. To start the discussion let me suggest "generators with a net electrical output or 20 MW or greater, connected through a step-up transformer with a high voltage rating of 100 kV or higher."

   The wording in the third bullet point for MOD-024-1 and MOD-025-1 in the Detail Description should be changed from "Consider Requiring" to just "Require".

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Group Comments (Complete this page if comments are from a group.)

Group Name: Entergy - Fossil Operations;Nuclear; System Planning & Operations (Generation)

Lead Contact: Will Franklin

Contact Organization: Entergy System Planning and Operations

Contact Segment: 6

Contact Telephone: 281-297-3456

Contact E-mail: wfrankl@entergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
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Arthur Howell	Entergy Fossil Operations	SERC	5
Jules Guillot	Entergy Fossil Operations	SERC	5
Thomas Barnett	Entergy Nuclear	SERC	5

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   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: It is questionable whether there is a reliability related need for these standards. The field tests are not complete, but initial results show that PRC-024 and MOD-027 are difficult to perform, give questionable results, and may not be translated into better models or higher reliability. MOD-026 is also difficult to translate into better models or higher reliability.

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments: However, there is no need increase the scope and test multiple points for MOD-025 for leading and lagging. This will not improve reliability or accurate modeling.

3. The scope of this project includes:

- Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
- Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
- Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☐ Yes

☒ No

Comments: The scope of MOD-025 has been expanded beyond what is stated above. The changes to the four field test standards should be based on the field test results up to and including their elimination if so recommended.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: MOD-24 & 25 should not be increased beyond their current scope. Multiple test points cost time and money, and increase the potential of plant trips, but do not improve reliability. The rest of the standards should be judged based on the results of the field test and significantly modified or eliminated if the field test show that they are very difficult to perform, give questionable results or do not improve the reliability of the bulk power system.

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

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NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☒ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments: The present legacy document ECAR Document 4 details the testing and is sufficient to cover the present accurary for a regional basis. The standards if spread to a national level will need to look at the difference between summer peaking regions and winter peaking. Presently the testing in RFC follows ECAR Document 4 which corrects the testing for average ambient conditions which is left up to the discretion of the testing personnel. The temperature conditions of the water inlet or ambient air needs to be defined.

3. The scope of this project includes:

- Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
- Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
- Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments: The project should account for potential regional differences. See comment on question # 5 below.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: It is recommended that the SAR be written to include the Generator Operator entity. If the drafting team determines only the GO is applicable and that the GOP is not needed it can be removed. As stated above, the SDTs can reduce scope but not expand. The Generator Operator may have involvement in PRC-024.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance: Not aware of existing, but potential for regional differences exist.
   Comments: The fill-in-the-blank needs to take into account regional differences such as summer or winter peaking conditions. The standard needs to address the main factor in generation capacity which is inlet water temperatures on once through cooling units and ambient temperature and humidity on cooling towers and combustion turbines.

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments: Aware of none.

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Comments: On page SAR-3 under PRC-024-1, the bullet "Add requirement for the Transmission Owner and Generator Owner to coordinate protection systems" should be revised or removed. If it is included, it should be revised to specifically state what protection schemes are being coordinated via this standard. Otherwise it should be removed because the coordination of the transmission and generation protection is covered in PRC-001-1 R3 and R4.

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

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NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☒ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: It is our understanding and hope that the results of the recent field test will be considered during development of the Standards.

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and

- Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments:

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Depending on the Requirements that are developed during the standard drafting phase, the Generator Operator may be an applicable entity.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance: Possible
   Comments: For Québec Interconnection, there might be some specific value for frequency range applicable for PRC-024 and PRC-019

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice: No
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: The industry should be provided the opportunity to comment on and provide suggestions for the periodicity and magnitude of the testing.

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Ron Falsetti	
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are “pending” with FERC because they include “fill-in-the-blank” requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC’s Reliability Standards Development Procedure and the ERO Sanction Guidelines,

   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and

   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☒ No

Comments: The SDT should consider the term characteristics during the review of the standards. The following is an example of:

-PRC-019-1

R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation could be to define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions.

In other words, the terms "characteristics" and "setpoints/settings" are presented in the requirements without clearly clarifying the meaning of the terms. “Characteristic” could mean something like a Generator capability curve (or any operating curve for that matter or nomograms) where the operations are defined by a “bounded region of operation” as such and is kind of “analog” in nature. “Setpoint/Setting” on the other hand could be something like a Generator Under-frequency trip setting where there are “set-points” for tripping – kind of “digital” in nature. Is this what the SDT means by these terms. Please clarify.

As the standards are reviewed, there are specific questions that need to be addressed such as:

MOD-025-1

R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output?

Also, What will define the need to revisit this when equipment changes occur?

In addition, the SDT should consider additional field tests for all the changes associated with the revised standard.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can “reduce” but cannot “expand” this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

☒ Yes

☒ No

Comments: We agree that the list covers all the reliability functions that are listed in the existing standards. However, in view of the expected industry debate on this issue, it may be prudent to add Generator Operator to the list in the event that any of the six standards should be revised to hold Generator Operators responsible for any tasks.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
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	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	IRC Standards Review Committee
Lead Contact:	Charles Yeung
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Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Castle	NYISO	NPCC	2
Alicia Daugherty	PJM	RFC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
William Phillips	MISO	RFC	2

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

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You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
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   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,

   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and

   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☒ No

Comments: The SDT should consider the term characteristics during the review of the standards. Sections below are identified as locations for clarification.
-PRC-019-1
R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation would be define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions. What is meant by characterisitics, if the characteristics are not defined as the setpoint?

As the standards are reviewed, there are specific questions that need to be addressed such as:
MOD-025-1
R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output?

Also, What will define the need to revisit this when equipment changes occur?

The SDT should also identify a date for compliance for each of the requirements and measures. Here are a few examples:

-MOD-024-1
M1 & M3 - Will need to prescribed a date for compliance

-MOD-026-1
M3 - Will need to prescribed a date for compliance

-MOD-027-1
M1 & M3 - Will need to prescribed a date for compliance

In addition the SDT should consider additional field tests for all the changes associated with the revised standard. Also careful consideration needs to be provided to the implementation plans.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can “reduce” but cannot “expand” this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

☒ Yes

☒ No

Comments: The SDT should consider applicability to Generator Operators who will be required to actually perform the tests.

The SDT should also review the applicablity of this SAR to the Reliability Coordinator. It is unclear at this time what role the RC will have in requirements associated with this standard.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: There is a reliability need for this SAR, but the Industry must be allowed to comment on the periodicity of the tests. There should be justification for annual testing requirements, since some characteristics do not change appreciably over time.

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Kathleen Goodman	
Organization:	ISO New England	
Telephone:	(413) 535-4111	
E-mail:	(413) 535-4343	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

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Background Information

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PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

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You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,

   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and

   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☒ No

Comments: The SDT should consider the term characteristics during the review of the standards. The following is an example of:
-PRC-019-1
R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation would be define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions. What is meant by characterisitics, if the characteristics are not defined as the setpoint?

As the standards are reviewed, there are specific questions that need to be addressed such as:
MOD-025-1
R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output?

Also, What will define the need to revisit this when equipment changes occur?

The SDT should also identify a date for compliance for each of the requirements and measures. Here are a few examples:

-MOD-024-1
M1 & M3 - Will need to prescribed a date for compliance

-MOD-026-1
M3 - Will need to prescribed a date for compliance

-MOD-027-1
M1 & M3 - Will need to prescribed a date for compliance

In addition the SDT should consider additional field tests for all the changes associated with the revised standard. Also careful consideration needs to be provided to the implementation plans.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can “reduce” but cannot “expand” this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

☒ Yes

☒ No

Comments: ISO New England asked the SDT to consider appliability to Generator Operators who will be required to actually perform the tests.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: There is a reliability need for this SAR, but the Industry must be allowed to comment on the periodicity and magnitude of the tests. There should be justification for annual testing since characteristics do not change appreciably over time.

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	MRO NSRS
Lead Contact:	Pam Oreschnick
Contact Organization:	Xcel Energy
Contact Segment:	10
Contact Telephone:	612-337-2376
Contact E-mail:	pamela.j.oreschnick@xcelenergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Carol Gerou	Minnesota Power	MRO	10
Joe Knight	Great River Energy	MRO	10
Dave Rudolph	Basin Electric Power Cooperative	MRO	10
Mike Brytowski	Midwest Reliability Organization	MRO	10
27 Additional MRO Members	Companies not named above	MRO	10

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

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MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

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You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments:

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: Under Draft PRC-024-1 on the SAR form, the fourth bullet says "Add a requirement for the Transmission Owner and Generator Owner to coordinate protection systems". This is already required and measured under PRC-001-1, and should therefore not be added as a requirement in PRC-024-1.

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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	NPCC CP9 Reliability Standards Working Group
Lead Contact:	Guy V. Zito
Contact Organization:	Northeast Power Coordinating Council
Contact Segment:	10
Contact Telephone:	212-840-100
Contact E-mail:	gzito@npcc.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Roger Champagne	HydroQuebec TransEnergie	NPCC	1
David Kiguel	Hydro One Networks	NPCC	1
Don Nelson	MA PUC	NPCC	9
Mike Gopinathan	Northeast Utilities	NPCC	1
Ralph Rufrano	New York Power Authority	NPCC	1
Mike Rinalli	National Grid US	NPCC	1
Randy Macdonald	New Brunswick System Operator	NPCC	2
Kathleen Goodman	ISO-New England	NPCC	2
Bill Shemley	ISO-New England	NPCC	2
Ed Thompson	Con-Edison	NPCC	1
Al Adamson	New York State Reliability Council	NPCC	10
Guy Zito	NPCC	NPCC	10
Greg Campoli	New York ISO	NPCC	2

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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MOD-027 — Verification of Generator Unit Frequency Response

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: It is our understanding and hope that the results of the recent field test will be considered during development of the Standards.

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,

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- Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments: The SDT should consider additional field tests for all the changes associated with the revised standard.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can “reduce” but cannot “expand” this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Depending on the Requirements that are developed during the standard drafting phase, the Generator Operator may be an applicable entity.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance: No
   Comments: Within the Québec Interconnection, there might be some specific value for frequency range applicable for PRC-024 and PRC-019 and this should be allowed for in the standard drafting phase.

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice: No
   Comments:

7. If you have any other comments on this SAR that you haven’t already mentioned above, please provide them here:

   Comments: The industry should be provided the opportunity to comment on and provide suggestions for the periodicity and magnitude of the testing.

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<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: Richard Kafka</td></tr>
<tr><td colspan="3">Organization: Pepco Hodlings, Inc. - PHI</td></tr>
<tr><td colspan="3">Telephone: 301-469-5274</td></tr>
<tr><td colspan="3">E-mail: rjkafka@pepcoholdings.com</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
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☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
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</table>

Group Comments (Complete this page if comments are from a group.)

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Lead Contact:

Contact Organization:

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Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

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Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments:

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

☐ Yes

☒ No

Comments: Generator Operator should be added.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

Regional Variance:
Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

Business Practice:
Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Comments:

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
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<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
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<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: Phil Riley

Contact Organization: Public Service Commission of South Carolina

Contact Segment: 9

Contact Telephone: 803-896-5154

Contact E-mail: philip.riley@psc.sc.gov

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
Elizabeth B. "Lib" Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
John E. "Butch" Howard	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
C. Robert "Bob" Moseley	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes

   ☐ No

   Comments:

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
   - Addressing issues identified in FERC Order 693.

Do you agree with this scope? If not, please explain in the comment area.

☒ Yes

☐ No

Comments:

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance:
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice:
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments:

Please use this form to submit comments on the SAR for Generator Verification. Comments must be submitted by **May 21, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "**Generator Verification**" in the subject line. If you have questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
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☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	SERC: Generator Standards Field Test Task Force
Lead Contact:	**Lee Taylor**
Contact Organization:	**Task Force Chairman**
Contact Segment:	**Region**
Contact Telephone:	205-257-7467
Contact E-mail:	**ltaylor**@southernco.com

Additional Member Name	Additional Member Organization	Region*	Segment*
John Loftis	Dominion Virginia Power	**SERC**	**1**
Larry Whanger	Dominion Virginia Power	**SERC**	**5**
Art Howell	Entergy	SERC	5
Stan Jaskot	Entergy	SERC	5
Pat Longshore	SCE&G	SERC	5
Pat Huntley	SERC Reliability Corp.	SERC	10
Lee Taylor	Southern Company Services, Inc.	SERC	1
Tom Higgins	Southern Company Services, Inc.	SERC	5
David Williams	US Army Corps of Engineers	SERC	9

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☐ Yes
   ☐ No

   Comments: At this point in time we cannot determine if there is a reliability related need to finalize these standards. The results of the field test by the 4 participating RROs will not be complete until late June 2007. The 4 RROs, in support of the NERC Field Test team, have spent significant resources in an attempt to implement procedures and subsequently carry out the draft Reliablity Standard requirements. Thus, in order to ensure proper consideration is given to the results of the field tests, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test. Recommend that the last sentence in the paragraph in the SAR on page SAR-3 under "Detailed Description" be modified to: "In addition, the SDT will consider and address all applicable FERC Orders, including Order 693, in addition to any modifications, deficiencies, and other items as found in the NERC Phase III-IV Planning Standard Field Tests, and in addition the following porposed changes for each of the six standards in this set of standards:"

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

   ☒ Yes
   ☐ No

Comments: However, the scope statement for MOD-025 includes increased scope: (scope creep to require expanded verification to include multiple operating points). The scope of this standard needs to be restricted to that of the current version!

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
   - Addressing issues identified in FERC Order 693.

   Do you agree with this scope? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The scope of MOD-025 has been expanded beyond what is stated above. The changes to the four field test standards should be based on the field test results up to and including their elimination if so recommended.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The Generator Operator should be added to the list of possible applicable functional entities on page 6 of the SAR.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance: none
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice: none
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: The scope of MOD-024 and MOD-025 should not be expanded beyond the scope contained in the current version of these two standards. The results of the field test for the other 4 Draft Reliability Standards by the 4 participating RROs will not be complete until late June 2007. Thus, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test.

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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	Southern Company - Transmission
Lead Contact:	Jim Busbin
Contact Organization:	Southern Company Services, Inc.
Contact Segment:	1
Contact Telephone:	205-257-6357
Contact E-mail:	jybusbin@southernco.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Marc Butts	Southern Company Services, Inc.	SERC	1
J. T. Wood	Southern Company Services, Inc.	SERC	1
Roman Carter	Southern Company Services, Inc.	SERC	1
Keith Calhoun	Southern Company Services, Inc.	SERC	1
Terry Crawley	Southern Company Services, Inc.	SERC	5
Tom Higgins	Southern Company Services, Inc.	SERC	5
John Ciza	Southern Company Services, Inc.	SERC	6

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Generator Verification SAR calls for finalizing the last four Phase III & IV standards (subsequent to field testing) and calls for revising two of the Phase III & IV standards that were approved by the NERC Board of Trustees but not by FERC. All six standards need to conform to the latest version of the ERO Sanction Guidelines and Reliability Standards Development Procedure and all need to address FERC concerns identified in FERC Order 693. The standards associated with this SAR are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

The SAR drafting team would like to receive comments on this SAR. Please review the SAR, answer the questions on the following pages, and e-mail the form to sarcomm@nerc.net with the subject "**Generator Verification**" by **May 21, 2007**.

You do not have to answer all questions.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

   Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR. Do you agree that there is a reliability-related need to finalize these standards? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: We are in agreement with the comments made by the SERC Generator Standards Field Test Task Force to this question. To re-state their comments here, "At this point we cannot determine if there is a reliability related need to finalize these standards. The results of the field test by the 4 participating RROs will not be complete until late June 2007. The 4 RROs, in support of the NERC Field Test team, have spent significant resources in an attempt to implement procedures and subsequently carry out the draft Reliability Standard requirements. Thus, in order to ensure proper consideration is given to the results of the field tests, the scope of the SAR should make it clear that the decision by the SDT to either refine, significantly revise or delete these standards should be heavily weighted on the outcome of the field test. (We) Recommend that the last sentence in the paragraph in the SAR on page SAR-3 under "Detailed Description" be modified to: ""In addition, the SDT will consider and address all applicable FERC Orders, including Order 693, in addition to any modifications, deficiencies, and other items as found in the NERC Phase III-IV Planning Standard Field Tests, and in addition the following proposed changes for each of the six standards in this set of standards:"

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability.

   To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?

☐ Yes

☒ No

Comments: The scope statement for both of these standards includes increases in their scope -- MOD-024 now reflects increased demonstration requirements and MOD-025 scope has crept to require expanded verification to include multiple operating points. The scope of these two standards should to be restricted to that of the current versions.

3. The scope of this project includes:

   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
   - Addressing issues identified in FERC Order 693.

   Do you agree with this scope? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: We are essentially in agreement with the three bullet points included in this question (and project); however, we are not in agreement with the scope of the SAR, specifically as it relates to MOD-024 and MOD-025. The scope of MOD-024 and MOD-025 have both been expanded beyond what is stated in the bullet points of this question. As we point out in our response to Question #2, MOD-024 now reflects increased demonstration requirements and MOD-025 scope has expanded (crept) to require expanded verification to include multiple operating points. The changes to the other four standards (PRC-019, PRC-024, MOD-026 and MOD-027) should be based on the field test results up to, and including, their elimination, if so recommended.

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.) Do you agree with the list of proposed applicable functional entities? If you feel that the list should be modified, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The list of possible applicable functional entities found on page 6 of the SAR should include Generator Operators. It seems to us that generator testing involving real and reactive power quantites will not be possible without the inclusion of this functional entity.

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:

   Regional Variance: None.
   Comments:

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice:

   Business Practice: None.
   Comments:

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

   Comments: The scope of MOD-024 and MOD-025 should not be expanded beyond the scope contained in the current version of these two standards. As for the other four standards; PRC-019, PRC-024, MOD-026 and MOD-027, the timing of the subject SAR appears to be premature since the field testing is not complete.

Consideration of Comments on the First Posting of the SAR for Generator Verifications

The members of the SAR drafting team for Project 2007-09 Generator Verification thank all commenters who submitted comments on Draft 1 of the SAR. This SAR was posted for a 30-day public comment period from April 20 through May 21, 2007. The requester asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 16 sets of comments, including comments from 63 different individuals from more than 35 organizations representing 7 of the 10 Industry Segments as shown in the table on the following pages.

In response to the comments received, the SAR drafting team has revised the SAR for Project 2007-09 Generator Verification as follows:

- Added the Generator Operator and Reliability Coordinator as reliability functions that may have responsibilities in the proposed standards.
- Added language to clarify that the standard drafting team will consider the Phase III & IV field test results when developing the standards associated with this project.

In addition, the SAR drafting team received some comments recommending specific modifications to requirements that were outside the scope of responsibility of the SAR drafting team. These comments have been collected and added as Attachment 1 to the SAR for resolution during standard drafting.

Based on the comments received, the SAR drafting team recommends that the Standards Committee accept the revised SAR for Project 2007-09 Generation Verification for:

- New standards to be finalized as part of this project:
  - PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
  - PRC-024 — Generator Performance During Frequency and Voltage Excursions
  - MOD-026 — Verification of Models and Data for Generator Excitation System Functions
  - MOD-027 — Verification of Generator Unit Frequency Response
- Existing standards to be revised as part of this project:
  - MOD-024 — Verification of Generator Gross and Net Real Power Capability
  - MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure manual: http://www.nerc.com/standards/newstandardsprocess.html

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad K. Ness	AEP	✓				✓	✓				
2.	Anita Lee (G1)	AESO		✓								
3.	John E. Sullivan	Ameren	✓		✓							
4.	Robert Ferguson	Ameren Services						✓				
5.	Rich Young	ATC LLC.	✓									
6.	Dave Rudolph (G7)	Basin Electric Power Cooperative	✓		✓		✓	✓				
7.	Brent Kingsford (G1)	CAISO		✓								
8.	Ed Thompson (G2)	Con-Edison	✓		✓			✓				
9.	John Loftis (G5)	Dominion Virginia Power	✓		✓							
10.	Larry Whanger (G5)	Dominion Virginia Power					✓					
11.	Art Howell (G5)	Entergy	✓		✓		✓					
12.	Stan Jaskot (G5)	Entergy					✓					
13.	Will Franklin (G6)	Entergy						✓				
14.	Arthur Howell (G6)	Entergy Fossil Organization					✓					
15.	Jules Guillot (G6)	Entergy Fossil Organization					✓					
16.	Stanley Jaskot (G6)	Entergy Fossil Organization					✓					
17.	Thomas Barnett (G6)	Entergy Fossil Organization					✓					
18.	Steve Myers (G1)	ERCOT		✓								✓
19.	Doug Hohlbaugh	FirstEnergy	✓									
20.	Joe Knight (G7)	Great River Energy	✓		✓		✓					
21.	Roger Champagne (I) (G2)	HQT	✓									
22.	David Kiguel (G2)	Hydro One Networks	✓		✓							
23.	Ron Falsetti (I) (G1)	IESO		✓								
24.	Kathleen Goodman	ISO- NE		✓								

	(I) (G2)											
25.	Matt Goldberg (G1)	ISO-NE		✓								
26.	Bill Shemley (G2)	ISO-NE		✓								
27.	Don Nelson (G2)	MA PUC									✓	
28.	Mike Brytowski (G7)	Midwest Reliability Organization										✓
29.	Carol Gerou (G7)	Minnesota Power	✓		✓		✓	✓				
30.	William Phillips (G1)	MISO		✓								
31.	Mike Rinalli (G2)	National Grid US	✓									
32.	Randy Macdonald (G2)	New Brunswick System Operator		✓								
33.	Mike Gopinathan (G2)	Northeast Utilities	✓									
34.	Guy V. Zito (G2)	NPCC										✓
35.	Greg Campoli (G2)	NYISO		✓								
36.	Ralph Rufrano (G2)	NY Power Authority	✓									
37.	Jim Castle (G1)	NYISO		✓								
38.	Al Adamson (G2)	NYSRC										✓
39.	Richard Kafka	PHI	✓		✓			✓				
40.	Alicia Daugherty (G1)	PJM		✓								
41.	C. Robert Moseley (G4)	PSC of SC									✓	
42.	David A. Wright (G4)	PSC of SC									✓	
43.	Elizabeth B. Fleming (G4)	PSC of SC									✓	
44.	G. O'Neal Hamilton (G4)	PSC of SC									✓	
45.	John E. Howard (G4)	PSC of SC									✓	
46.	Mignon L. Clyburn (G4)	PSC of SC									✓	
47.	Phil Riley (G4)	PSC of SC									✓	
48.	Randy Mitchell (G4)	PSC of SC									✓	
49.	Pat Longshore (G5)	SCE&G			✓		✓	✓				
50.	Pat Huntley (G5)	SERC Reliability Corp										✓
51.	Lee Taylor (G5)	Southern Company	✓									
52.	J.T Wood (G3)	Southern Company SI	✓									
53.	Jim Busgin (G3)	Southern Company SI										
54.	John Ciza (G3)	Southern Company SI						✓				
55.	Keith Calhoun (G3)	Southern Company SI	✓									
56.	Marc Butts (G3)	Southern Company SI	✓									
57.	Roman Carter (G3)	Southern Company SI	✓									

58.	Terry Crawley (G3)	Southern Company SI					✓					
59.	Tom Higgins (G3)	Southern Company SI					✓					
60.	Tom Higgins (G5)	Southern Company SI					✓					
61.	Charles Yeung (G1)	SPP										✓
62.	David Williams (G5)	US Army Corps of Engineers									✓	
63.	Pam Oreschnick(G7)	Xcel Energy	✓		✓		✓	✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – IRC Standards Review Committee
G2 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G3 – Southern Company Services
G4 – PSC of South Carolina
G5 – SERC Generator Standards Filed Test Task Force
G6 – Entergy
G7 – MRO NSRS

Index to Questions, Comments, and Responses

1. Do you agree that there is a reliability-related need to finalize these standards (MOD-026, MOD-027, PRC-024, PRC-019)? 7
2. Do you agree that there is a reliability-related need to revise these standards (MOD-024 and MOD-025) to support accurate modeling?..11
3. Do you agree with this scope? 14
4. Do you agree with the list of proposed applicable functional entities?.........................19
5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance. 22
6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice. 24
7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:...25

1. The field test from the Phase III & IV project included PRC-019, PRC-024, MOD-026, and MOD-027. The field testing has shown that requirements can be developed and incorporated into standards for the following:

   - Generator excitation system verification (MOD-026)
   - Generator frequency response verification (MOD-027)
   - Expectations for generators to remain connected during specified voltage and frequency excursions (PRC-024)
   - Coordination of generator voltage regulator controls and limit functions with generator capabilities and protective relays (PRC-019)

Finalizing these standards will require significant changes that are outside the scope of the original Phase III & IV SARs, which is why the draft standards have been included in the scope of this new SAR.

Do you agree that there is a reliability-related need to finalize these standards (MOD-026, MOD-027, PRC-024, PRC-019)? If not, please explain in the comment area.

Summary Consideration: Most commenters agreed that there is a reliability-related need to finalize the four Phase III & IV standards that were field tested.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Ameren Services			At this point in time we cannot determine if there is a reliability related need to finalize these standards. The results of the field test by the 4 participating RROs will not be complete until late June 2007. The 4 RROs, in support of the NERC Field Test team, have spent significant resources in an attempt to implement procedures and subsequently carry out the draft Reliablity Standard requirements. Thus, in order to ensure proper consideration is given to the results of the field tests, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test. Recommend that the last sentence in the paragraph in the SAR on page SAR-3 under “Detailed Description” be modified to: “In addition, the SDT will consider and address all applicable FERC Orders, including Order 693, in addition to any modifications, deficiencies, and other items as found in the NERC Phase III-IV Planning Standard Field Tests, and in addition the following porposed changes for each of the six standards in this set of standards:”
Response: The NERC Phase III-IV Field Tests will be complete on June 19, before the subject SAR is completed and before the Generation Verification SDT is formed. The SAR DT is meeting at the same time that the field test reports are being given so that the DT will have first hand knowledge of the results. The intention of the SAR was to clearly direct the SDT to give			

Question #1			
Commenter	**Yes**	**No**	**Comment**
proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
Entergy		☑	It is questionable whether there is a reliability related need for these standards. The field tests are not complete, but initial results show that PRC-024 and MOD-027 are difficult to perform, give questionable results, and may not be translated into better models or higher reliability. MOD-026 is also difficult to translate into better models or higher reliability.
Response: During the public posting for comment of the proposed draft Phase III-IV Standards, the industry did provide comments questioning the feasibility of performing the draft requirements, the industry did consistently affirm the reliability need. The purpose of the field test was to specifying confirm whether the requirements were feasible. In addition, since the NERC Phase III-IV Field Tests will be complete on June 19, before the subject SAR is completed and before the Generation Verification SDT is formed. The SAR DT is meeting at the same time that the field test reports are being given so that the DT will have first hand knowledge of the results. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
SERC GSFT-TF			At this point in time we cannot determine if there is a reliability related need to finalize these standards. The results of the field test by the 4 participating RROs will not be complete until late June 2007. The 4 RROs, in support of the NERC Field Test team, have spent significant resources in an attempt to implement procedures and subsequently carry out the draft Reliablity Standard requirements. Thus, in order to ensure proper consideration is given to the results of the field tests, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test. Recommend that the last sentence in the paragraph in the SAR on page SAR-3 under “Detailed Description” be modified to: “In addition, the SDT will consider and address all applicable FERC Orders, including Order 693, in addition to any modifications, deficiencies, and other items as found in the NERC Phase III-IV Planning Standard Field Tests, and in addition the following porposed changes for each of the six standards in this set of standards:”
Response: The NERC Phase III-IV Field Tests will be complete on June 19, before the subject SAR is completed and before the Generation Verification SDT is formed. The SAR DT is meeting at the same time that the fiedld test reports are being given so that the DT will have first hand knowledge of the results. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
SCT		☑	We are in agreement with the comments made by the SERC Generator Standards Field Test Task Force to this question. To re-state their comments here, “At this point we cannot determine if there is

Question #1			
Commenter	**Yes**	**No**	**Comment**
			a reliability related need to finalize these standards. The results of the field test by the 4 participating RROs will not be complete until late June 2007. The 4 RROs, in support of the NERC Field Test team, have spent significant resources in an attempt to implement procedures and subsequently carry out the draft Reliability Standard requirements. Thus, in order to ensure proper consideration is given to the results of the field tests, the scope of the SAR should make it clear that the decision by the SDT to refine, significantly revise or delete these standards should be heavily weighted on the outcome of the field test. (We) Recommend that the last sentence in the paragraph in the SAR on page SAR-3 under "Detailed Description" be modified to: ""In addition, the SDT will consider and address all applicable FERC Orders, including Order 693, in addition to any modifications, deficiencies, and other items as found in the NERC Phase III-IV Planning Standard Field Tests, and in addition the following proposed changes for each of the six standards in this set of standards:"
Response: The SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
HQT NPCC CP9 RSWG	☑		It is our understanding and hope that the results of the recent field test will be considered during development of the Standards
Response: The SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
AEP	☑		
Ameren	☑		
ATC LLC.	☑		
FirstEnergy	☑		
IESO	☑		
IRC-SRC	☑		
ISO-NE	☑		
MRO	☑		
PHI	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
PSC SC	☑		

2. Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability. To be enforceable, these standards need to be revised.

Do you agree that there is a reliability-related need to revise these standards (MOD-024 and MOD-025) to support accurate modeling?

Summary Consideration: Most commenters agreed that there is a reliability-related need to revise MOD-024 and MOD-025.

Question #2			
Commenter	**Yes**	**No**	**Comment**
SCT		☑	The scope statement for both of these standards includes increases in their scope -- MOD-024 now reflects increased demonstration requirements and MOD-025 scope has crept to require expanded verification to include multiple operating points. The scope of these two standards should to be restricted to that of the current versions.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. In addition the FERC stated concerns about the lack of clarity in MOD-024.			
SERC GSFT-TF	☑		However, the scope statement for MOD-025 includes increased scope: (scope creep to require expanded verification to include multiple operating points). The scope of this standard needs to be restricted to that of the current version!
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration.			
Ameren	☑		With regards to the scope of MOD-025, it should not be necessary to include a blanket requirement for verification of reactive power capability at multiple points for all generators. However, should a generator frequently have difficulty reaching its stated reactive power output, additional testing

Question #2			
Commenter	**Yes**	**No**	**Comment**
			requirements for that generator would be indicated.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration.			
Entergy	☑		However, there is no need increase the scope and test multiple points for MOD-025 for leading and lagging. This will not improve reliability or accurate modeling.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration.			
FirstEnergy	☑		The present legacy document ECAR Document 4 details the testing and is sufficient to cover the present accurary for a regional basis. The standards if spread to a national level will need to look at the difference between summer peaking regions and winter peaking. Presently the testing in RFC follows ECAR Document 4 which corrects the testing for average ambient conditions which is left up to the discretion of the testing personnel. The temperature conditions of the water inlet or ambient air needs to be defined.
Response: Thank you for your suggestions. Your specific concerns regarding summer and winter peaking regions and temperatures which impact capabilities will be forwarded to the Standard Drafting Team.			
AEP	☑		
Ameren Services	☑		
ATC LLC.	☑		
HQT	☑		
IESO	☑		

Question #2			
Commenter	Yes	No	Comment
IRD-SRC	☑		
ISO-NE	☑		
MRO	☑		
NPCC CP9 RSWG	☑		
PHI	☑		
PSC SC	☑		

3. The scope of this project includes:
   - Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,
   - Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and
   - Addressing issues identified in FERC Order 693.

Do you agree with this scope?

If not, please explain in the comment area.

Summary Consideration: Most commenters indicated they do agree with the scope of this project. Some commenters suggested that the scope be modified to specifically include a notation that the standard drafting team will consider the results of the field tests, and the drafting team did modify the SAR to clarify that the project does include the following:
   - Considering and addressing issues identified during Phase III & IV field testing.

Some commenters suggested specific changes to the technical content of the requirements in the draft standards. The SAR DT modified the SAR to clarify that the standard drafting team must consider the comments submitted by stakeholders during the posting of the SAR, and the SAR DT appended these comments to the SAR.

Question #3			
Commenter	**Yes**	**No**	**Comment**
SCT		☑	We are essentially in agreement with the three bullet points included in this question (and project); however, we are not in agreement with the scope of the SAR, specifically as it relates to MOD-024 and MOD-025. The scope of MOD-024 and MOD-025 have both been expanded beyond what is stated in the bullet points of this question. As we point out in our response to Question #2, MOD-024 now reflects increased demonstration requirements and MOD-025 scope has expanded (crept) to require expanded verification to include multiple operating points. The changes to the other four standards (PRC-019, PRC-024, MOD-026 and MOD-027) should be based on the field test results up to, and including, their elimination, if so recommended.
Response: In FERC Order 693, the ERO was directed to modify MOD-024-1 and 025-1 including "require verification of reactive power capability at multiple points….". As such, the SDT is obligated to address, as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), the FERC directives or propose other viable alternatives that achieve that same objective. The SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field			

Question #3			
Commenter	**Yes**	**No**	**Comment**
tests. The SAR has been clarified accordingly.			
SERC GSFT-TF		☑	The scope of MOD-025 has been expanded beyond what is stated above. The changes to the four field test standards should be based on the field test results up to and including their elimination if so recommended.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points…." The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
Entergy		☑	The scope of MOD-025 has been expanded beyond what is stated above. The changes to the four field test standards should be based on the field test results up to and including their elimination if so recommended.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points…." The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration. The SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
IESO	☑	☑	The SDT should consider the term characteristics during the review of the standards. The following is an example of: PRC-019-1 R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation could be to define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions. In other words, the terms "characteristics" and "setpoints/settings" are presented in the requirements without clearly clarifying the meaning of the terms. "Characteristic" could mean something like a Generator capability curve (or any operating curve for that matter or nomograms) where the operations are defined by a "bounded region of

Question #3			
Commenter	**Yes**	**No**	**Comment**
			operation" as such and is kind of "analog" in nature. "Setpoint/Setting" on the other hand could be something like a Generator Under-frequency trip setting where there are "set-points" for tripping – kind of "digital" in nature. Is this what the SDT means by these terms. Please clarify. As the standards are reviewed, there are specific questions that need to be addressed such as: MOD-025-1 R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output? Also, What will define the need to revisit this when equipment changes occur? In addition, the SDT should consider additional field tests for all the changes associated with the revised standard.
Response: Thank you for your comments. They will all be forwarded to the SDT for their consideration. The task of the SDT is to clarify the current draft standards and remove RRO requirements. The commenter is encouraged to review and comment on the public postings by the future Generator Verification SDT. Regarding your comment concerning the field test results, the SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
IRC-SRC ISO-NE	☑	☑	The SDT should consider the term characteristics during the review of the standards. Sections below are identified as locations for clarification. -PRC-019-1 R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation would be define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions. What is meant by characterisitics, if the characteristics are not defined as the setpoint? As the standards are reviewed, there are specific questions that need to be addressed such as: MOD-025-1 R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output? Also, What will define the need to revisit this when equipment changes occur? The SDT should also identify a date for compliance for each of the requirements and measures. Here are a few examples: -MOD-024-1 M1 & M3 - Will need to prescribed a date for compliance -MOD-026-1 M3 - Will need to prescribed a date for compliance

Question #3			
Commenter	**Yes**	**No**	**Comment**
			-MOD-027-1 M1 & M3 - Will need to prescribed a date for compliance In addition the SDT should consider additional field tests for all the changes associated with the revised standard. Also careful consideration needs to be provided to the implementation plans.
Response: Thank you for your comments. They will all be forwarded to the SDT for their consideration. The task of the SDT is to clarify the current draft standards and remove RRO requirements. The commenter is encouraged to review and comment on the public postings by the future Generator Verification SDT. Regarding your comment concerning the field test results, the SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
FirstEnergy	☑		The project should account for potential regional differences. See comment on question # 5 below
Response: Your comment will be forwarded to the SDT for their consideration. The SAR Drafting Team encourages the commenter to review the future posting of the draft Reliability Standards proposed by the future Generation Verification SDT, and make specific comments if necessary.			
Ameren Services	☑		The scope of MOD-025 has been expanded beyond what is stated above. The changes to the four field test standards should be based on the field test results.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration. The SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.			
NPCC CP9 RSWG	☑		The SDT should consider additional field tests for all the changes associated with the revised standard.
Response:			

Question #3			
Commenter	**Yes**	**No**	**Comment**
The SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests, and the SAR will be clarified accordingly.			
AEP	☑		
ATC LLC.	☑		
HQT	☑		
MRO	☑		
PHI	☑		
PSC SC	☑		

4. Page 6 of the SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. (At this point additional industry debate is needed on which function or functions will be assigned responsibility for the requirements currently assigned to the RRO — and that debate is expected to take place during standard drafting as the requirements are refined. Note that the standard drafting team can "reduce" but cannot "expand" this list of responsible reliability functions during standard drafting.)

   Do you agree with the list of proposed applicable functional entities?

   If you feel that the list should be modified, please explain in the comment area.

Summary Consideration: Many commenters indicated that the Generator Operator should be added to the list of reliability functions with responsibilities in the revised standards and the drafting team modified the SAR to include the Generator Operator. In addition, one commenter suggested that the Reliability Coordinator may have additional requirements in the proposed standards, and the SAR DT adopted the suggestion to also add the Reliability Coordinator to the list of reliability functions that may have responsibilities in the proposed standards.

Question #4			
Commenter	**Yes**	**No**	**Comment**
ATC LLC.		☑	Generator Operator should be included.
Response: The SAR drafting team agrees and Generator Operator has been added to the list of responsible reliability functions.			
SCT		☑	The list of possible applicable functional entities found on page 6 of the SAR should include Generator Operators. It seems to us that generator testing involving real and reactive power quantites will not be possible without the inclusion of this functional entity.
Response: The SAR drafting team agrees and Generator Operator has been added to the list of responsible reliability functions.			
SERC GSFT-TF		☑	The Generator Operator should be added to the list of possible applicable functional entities on page 6 of the SAR.
Response: The SAR drafting team agrees and Generator Operator has been added to the list of responsible reliability functions.			
FirstEnergy		☑	It is recommended that the SAR be written to include the Generator Operator entity. If the drafting

Question #4			
Commenter	**Yes**	**No**	**Comment**
			team determines only the GO is applicable and that the GOP is not needed it can be removed. As stated above, the SDTs can reduce scope but not expand. The Generator Operator may have involvement in PRC-024.
Response: The SAR drafting team agrees and Generator Operator has been added to the list of responsible reliability functions.			
HQT		☑	Depending on the Requirements that are developed during the standard drafting phase, the Generator Operator may be an applicable entity.
Response: The SAR drafting team agrees and Generator Operator has been added to the list of responsible reliability functions.			
Entergy		☑	
IESO	☑	☑	We agree that the list covers all the reliability functions that are listed in the existing standards. However, in view of the expected industry debate on this issue, it may be prudent to add Generator Operator to the list in the event that any of the six standards should be revised to hold Generator Operators responsible for any tasks.
Response: The SAR drafting team agrees and Generator Operator has been added to the list of responsible reliability functions.			
IRC-SRC	☑	☑	The SDT should consider applicability to Generator Operators who will be required to actually perform the tests. The SDT should also review the applicability of this SAR to the Reliability Coordinator. It is unclear at this time what role the RC will have in requirements associated with this standard.
Response: The SAR drafting team agrees and Generator Operator has been added to the list of responsible reliability functions. The SAR drafting team also agrees that the SDT may determine it necessary for the Reliability Coordinator to be involved to the extent where verification activities are allowed or not for certain system conditions based on operational security analysis. Reliability Coordinator has been added to the list of responsible reliability functions.			
ISO-NE	☑	☑	ISO New England asked the SDT to consider applicability to Generator Operators who will be required to actually perform the tests.
Response:			

Question #4			
Commenter	**Yes**	**No**	**Comment**
The SAR drafting team agrees and Generator Operator will be added to the list of responsible reliability functions.			
NPCC CP9 RSWG		☑	Depending on the Requirements that are developed during the standard drafting phase, the Generator Operator may be an applicable entity.
Response: The SAR drafting team agrees and Generator Operator will be added to the list of responsible reliability functions.			
PHI		☑	Generator Operator should be added.
Response: The SAR drafting team agrees and Generator Operator will be added to the list of responsible reliability functions.			
Ameren Services	☑	☑	
MRO	☑		
PSC SC	☑		
AEP	☑		

5. If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance.

Summary Consideration: While some commenters identified the 'potential' for a regional variance, no commenters identified the need for any specific regional variances.

Question #5		
Commenter	**Regional Variance**	**Comment**
FirstEnergy		Not aware of existing, but potential for regional differences exist. The fill-in-the-blank needs to take into account regional differences such as summer or winter peaking conditions. The standard needs to address the main factor in generation capacity which is inlet water temperatures on once through cooling units and ambient temperature and humidity on cooling towers and combustion turbines.
Response: Your comment will be forwarded to the SDT for their consideration. The SAR Drafting Team encourages the commenter to review the future posting of the draft Reliability Standards proposed by the future Generation Verification SDT, and make specific comments if necessary.		
HQT	Possible	For Québec Interconnection, there might be some specific value for frequency range applicable for PRC-024 and PRC-019
Response: The SAR Drafting Team encourages the commenter to review the future posting of the draft Reliability Standards PRC-019 and PRC-024 proposed by the future Generation Verification SDT, and make specific comments if necessary. In removing the RRO requirement to establish requirements for frequency excursions, the SDT will need, as you indicate, to propose specific limits for excursions needed to develop a continent or interconnection wide requirement.		
NPCC CP9 RSWG	No	Within the Québec Interconnection, there might be some specific value for frequency range applicable for PRC-024 and PRC-019 and this should be allowed for in the standard drafting phase.
Response: The SAR Drafting Team encourages the commenter to review the future posting of the draft Reliability Standards PRC-019 and PRC-024 proposed by the future Generation Verification SDT, and make specific comments if necessary. In removing the RRO requirement to establish requirements for frequency excursions, the SDT will need, as you indicate, to propose specific limits for excursions needed to develop a continent or interconnection wide requirement.		

Question #5		
Commenter	**Regional Variance**	**Comment**
SCT	None	
Ameren Services	None	
SERC GSFT-TF	None	

6. If you are aware of any business practice that will be needed or that will need to be modified as a result of this project, please identify the business practice.

Summary Consideration: No commenter identified the need for a business practice to support the modified standards.

Question #6		
Commenter	**Business Practice**	**Comment**
FirstEnergy	-	Aware of none.
HQT	No	
NPCC CP9 RSWG	No	
SCT	None	
Ameren Services	None	
SERC GSFT-TF	None	

7. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Summary Consideration:

Question #7	
Commenter	**Comment**
AEP	Please transmit to the Standard Drafting Team the following specific suggested revisions to MOD-025: Key changes relate to FERC's requirement that regional "fill-in-the-blank" standards be rewritten as North American standards; these and other recommended changes are provided below: A. Introduction 1. Title: Verification of Generator [ ] Reactive Power Capabilities 3. Purpose: To ensure that [ ] steady-state models used for assessing Bulk Electric System reliability reflect realistic/usable generator reactive power capabilities. B. Requirements R1. The North American Electric Reliability Corporation (NERC) shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following: R1.5. Information to be reported to Regional Reliability Organization (RRO): R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1. and at Minimum Real Power output levels of generators. Net capabilities should be reported at the low- and high-voltage terminals of generator step-up (GSU) transformers. R1.5.3. Verified Real and Reactive Power of auxiliary loads fed from: (a) generator bus and (b) transmission system bus (listed separately). R1.5.5. System bus voltages (as scheduled and as verified), generator bus voltage and generator hydrogen pressure. R1.5.6. In-service transformer taps setting and impedance (including base quantities). R1.6. Requirement that sanity checks (or analysis) be used to ensure consistency/accuracy of reactive power capabilities obtained via measurement. R2. The RRO shall provide [ ] generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to ... R3. The Generator Owner shall follow NERC's procedures for verifying and reporting to RRO generator gross and net Reactive Power capabilities per R1. C. Measures M2. The RRO shall have written evidence that [ ] procedures... M3. The Generator Owner shall have written evidence it provided verified information of its generator gross and net Reactive Power capabilities, consistent with NERC's procedures.

Question #7	
Commenter	**Comment**
	D. Compliance This section should be revised to recognize that the procedures for generator Reactive Power capability verification will be written by NERC as a continent-wide standard. AEP recommends that Ape's Circular Letter OP-G-CL-011 (Reactive Capability Testing of Generators), developed over nearly two decades of testing experience and advocacy within the former ECAR region, be used as a reference in drafting this standard.
Response: Thank you for your suggestions. Your specific recommendations will be made available to the Standard Drafting Team.	
Ameren	MOD-026-1 and MOD-027-1: The existing language in R1.2 for each of these standards states that manufacturer data is one of the methods which can be utilized for verification of models and data. However, typical data for these types of models is generally not adequate to sufficiently characterize the models for use in system simulations.
Response: As part of the process of modifying the existing MOD-024 and 025 standards to remove the "fill in the blank" requirements and replacing them with requirements that can be applied on a continent-wide basis, the SDT will be charged to carefully consider the validity of each method that can be utilized for verification of models and data.	
Ameren Services	The scope of MOD-024 and MOD-025 should not be expanded beyond the scope contained in the current version of these two standards. The results of the field test for the other 4 Draft Reliability Standards by the 4 participating RROs will not be complete until late June 2007. Thus, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. In addition the FERC stated concerns about the lack of clarity in MOD-024. The NERC Phase III-IV Field Tests will be complete on June 19, before the subject SAR is completed and before the Generation Verification SDT is formed. The SAR DT is meeting at the same time that the field test reports are being given so that the DT will have first hand knowledge of the results. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.	
ATC LLC.	The SAR includes language requiring the SDT to identify any generators that should be exempt from compliance.

Question #7	
Commenter	**Comment**
	There are many standards both under this project and others (such as Project 2007-01) that need to consider applicability based on generator size and/or voltage. If these standards remain separate, this requirement will either force needless repetition of the same language in many standards, or there is a distinct possibility that differences will develop among the exemptions, making it very difficult for generator owners to know which of their generators are covered by which standards. I suggest there should be a global definition of minimum generator size to which all NERC Reliability Standards apply, much like the global definition of Bulk Electric System. To start the discussion let me suggest "generators with a net electrical output or 20 MW or greater, connected through a step-up transformer with a high voltage rating of 100 kV or higher." The wording in the third bullet point for MOD-024-1 and MOD-025-1 in the Detail Description should be changed from "Consider Requiring" to just "Require".
Response: Part of the work performed by the SDT is to clearly state the applicable entities and any specific characteristics. This was commented on by FERC repeatedly. The SDT will have to develop the "applicability" that is consistent with other NERC standards as you indicate. This will need to be done in concert with the definition of the BES and the compliance registration guidelines. Your comment will be forwarded to the SDT. The SAR Drafting Team agrees with your second comment and has changed the SAR accordingly.	
Entergy	MOD-24 & 25 should not be increased beyond their current scope. Multiple test points cost time and money, and increase the potential of plant trips, but do not improve reliability. The rest of the standards should be judged based on the results of the field test and significantly modified or eliminated if the field test show that they are very difficult to perform, give questionable results or do not improve the reliability of the bulk power system.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration. The SAR Drafting Team agrees. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.	
FirstEnergy	On page SAR-3 under PRC-024-1, the bullet "Add requirement for the Transmission Owner and Generator Owner to coordinate protection systems" should be revised or removed. If it is included, it should be revised to specifically state what protection schemes are being coordinated via this standard. Otherwise it should be removed because the coordination of the transmission and generation protection is covered in PRC-001-1 R3 and R4.

Question #7	
Commenter	**Comment**
Response: PRC-001-1 R3 requires "A Generator Operator or Transmission Operator shall coordinate NEW protective systems and CHANGES". R4 requires "Each Transmission Operator shall coordinate protection systems on MAJOR transmission lines and interconnections with NEIGHBORING Generator Operators …..." It is the task of the SDT to propose requirements as a result of this SAR that complement and/or supplement PRC-001-1. Based on the SDT considerations and/or comments received during public postings, the SDT may consider writing another SAR to address these issues in a revision of PRC-001.	
HQT NPCC CP9 RSWG	The industry should be provided the opportunity to comment on and provide suggestions for the periodicity and magnitude of the testing.
Response: Industry will have the opportunity to comment on all aspects of future drafts of the NERC Reliability Standards to be developed by the future Generator Verification SDT as required by the NERC Standard Development Procedure.	
IRC - SRC	There is a reliability need for this SAR, but the Industry must be allowed to comment on the periodicity of the tests. There should be justification for annual testing requirements, since some characteristics do not change appreciably over time.
Response: Thank you for your comments. They will all be forwarded to the SDT for their consideration. The task of the SDT is to clarify the current draft standards and remove RRO requirements. The commenter is encouraged to review and comment on the public postings by the future Generator Verification SDT.	
ISO-NE	There is a reliability need for this SAR, but the Industry must be allowed to comment on the periodicity and magnitude of the tests. There should be justification for annual testing since characteristics do not change appreciably over time.
Response:	
SCT	The scope of MOD-024 and MOD-025 should not be expanded beyond the scope contained in the current version of these two standards. As for the other four standards; PRC-019, PRC-024, MOD-026 and MOD-027, the timing of the subject SAR appears to be premature since the field testing is not complete.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other	

Question #7	
Commenter	**Comment**
viable alternatives that meet the same objective. The NERC Phase III-IV Field Tests will be complete on June 19, before the subject SAR is completed and before the Generation Verification SDT is formed. The SAR DT is meeting at the same time that the field test reports are being given so that the DT will have first hand knowledge of the results. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.	
SERC GSFT-TF	The scope of MOD-024 and MOD-025 should not be expanded beyond the scope contained in the current version of these two standards. The results of the field test for the other 4 Draft Reliability Standards by the 4 participating RROs will not be complete until late June 2007. Thus, the scope of the SAR should make it clear that the decision by the SDT to either refine / significantly revise / or delete these standards should be heavily weighted on the outcome of the field test.
Response: In FERC Order 693, the ERO was directed to modify MOD-025-1 to "require verification of reactive power capability at multiple points….". The SDT will be expected , as outlined in "Guidance to Standards Drafting Team Relative to FERC Order Nos. 693 and 890" (April 13, 2006), to address verification of reactive power capability at multiple points or provide other viable alternatives that meet the same objective. Your suggestion will be forwarded to the SDT for their consideration. The intention of the SAR was to clearly direct the SDT to give proper consideration to the results of the field tests. The SAR has been clarified accordingly.	
XCEL	Under Draft PRC-024-1 on the SAR form, the fourth bullet says "Add a requirement for the Transmission Owner and Generator Owner to coordinate protection systems". This is already required and measured under PRC-001-1, and should therefore not be added as a requirement in PRC-024-1.
Response: PRC-001-1 R3 requires "A Generator Operator or Transmission Operator shall coordinate NEW protective systems and CHANGES". R4 requires "Each Transmission Operator shall coordinate protection systems on MAJOR transmission lines and interconnections with NEIGHBORING Generator Operators ….." It is the task of the SDT to propose requirements as a result of this SAR that complement and/or supplement PRC-001-1. Based on the SDT considerations and/or comments received during public postings, the SDT may consider writing another SAR to address these issues in a revision of PRC-001.	

Standard Authorization Request Form

Title of Proposed Standard	Generator Verification (Project 2007-09)
Request Date	April 3, 2007
Modified Date	June 14, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: Bob Millard	☒	New Standards
Primary Contact: Bob Millard	☒	Revision to existing Standards:
Telephone: (708) 588-9886 Fax:	☐	Withdrawal of existing Standard
E-mail: bob.millard@rfirst.org	☐	Urgent Action

Purpose

The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

New standards to be finalized as part of this project are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

Standards to be revised as part of this project are:

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

Industry Need

All six of the standards included in this project address generator verifications needed to support bulk power system reliability. All six of the standards included in this project were originally "Phase III & IV Planning Measures" that were translated into new or proposed standards as part of the Version 0 translation effort. Stakeholders have already agreed that there is a reliability-related need for each of these standards as part of the work performed in association with the Phase III & IV Modeling SAR. In addition, each of the standards included in this project has some "fill-in-the-blank" requirements assigned to the Regional Reliability Organization that need to be replaced with more specific "continent-wide" requirements before the standards are approved.

Specifically:

- MOD-024-1 and MOD-025-1 were approved by the NERC Board of Trustees but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization (MOD-024-1 and MOD-025-1 require generator owners to verify the generator's gross and net real and reactive power capability using an RRO established procedure).

- PRC-019-1, PRC-024-1, MOD-026-1 and MOD-027-1 are draft standards that were developed under the Phase III & IV Modeling SAR that have not been presented to the NERC Board of Trustees yet. These four standards contain "fill-in-the-blank" requirements assigned to the Regional Reliability Organization (RRO) which were appropriate when the standards were initially drafted but are not appropriate under current requirements for approval of enforceable standards. Work on these standards to remove the "fill-in-the-blank" requirements under the Phase III & IV Modeling SAR is not authorized and therefore cannot be completed under the Phase III & IV Modeling SAR because the modifications needed to make the standards enforceable are outside the scope of the original Phase III & IV SARs. To properly complete these standards, a new SAR is needed and the prior SAR need to be terminated (termination of the Phase III & IV Modeling SAR will be performed outside the work of this SAR).
    - This set of standards includes verification of the generator's excitation system; verification of the generator's frequency response; verification that the generator can remain connected during specified voltage and frequency excursions; and verification that the generator's voltage regulator controls and limit functions have been coordinated with the generator's capabilities and protective relays.
    - The field test for this set of standards has shown that a standard can be written to support these verifications.

Brief Description

The scope of this project includes:

- modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Rules of Procedure,
- replacing the "fill-in-the-blank" requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners or operators of the bulk power system,
- considering and addressing issues identified in FERC orders, including the modifications to MOD-024-1 and MOD-025-1 as proposed in FERC Order 693, and
- considering and addressing issues identified during Phase III & IV field testing.

Detailed Description

The standards drafting team (SDT) will bring the six standards into conformance with the latest version of NERC's Reliability Standards Development Procedure and the ERO Rules of Procedure. In addition, the SDT will consider and address all applicable FERC Orders including but not limited to FERC Order 693, the field test results from the Phase III & IV field testing, issues raised by the industry during the posting of the SAR for Project 2007-09 Generator Verification identified in Attachment 1, and the following proposed changes for each of the six standards in this set of standards:

Draft PRC-019-1

- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft PRC-024-1

- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generators will remain connected during specified system frequency and voltage excursions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a requirement for the Transmission Owner and Generator Owner to coordinate protection systems
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

MOD-024-1:

- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with verification of generator gross and net real power capability
    - Consider requiring the generator owner to document the test conditions and

    - the relationships between test conditions and generator output
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

MOD-025-1:
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with verification of generator gross and net Reactive Power capability
    - Consider requiring verification of reactive power capability at multiple points over a unit's operating range
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft MOD-026-1
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with generator excitation system functions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft MOD-027-1
- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with generator unit frequency response

- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Reliability Functions

The Standard Drafting Team will Consider Applicability to All Functional Entities *(Check box for each one that may apply.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.Yes
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure. Yes
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
Phase III&IV Modeling	This SAR dated 11/17/04 initiated work on all six standards, two of which have been approved by the NERC BOT and four of which are still in draft phase, as referenced above above. The SDT working on the four draft standards will be terminated and undertaken by the new SDT for this SAR.

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

Issues Raised by Industry During 1st Posting of SAR for Project 2007-09 Generator Verification Which are Outside the Responsibility of the SAR Drafting Team

Question 2 of the Comment Form: *Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability. To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?*

Ameren commented:

With regards to the scope of MOD-025, it should not be necessary to include a blanket requirement for verification of reactive power capability at multiple points for all generators. However, should a generator frequently have difficulty reaching its stated reactive power output, additional testing requirements for that generator would be indicated.

FirstEnergy commented:

The present legacy document ECAR Document 4 details the testing and is sufficient to cover the present accurary for a regional basis. The standards if spread to a national level will need to look at the difference between summer peaking regions and winter peaking. Presently the testing in RFC follows ECAR Document 4 which corrects the testing for average ambient conditions which is left up to the discretion of the testing personnel. The temperature conditions of the water inlet or ambient air needs to be defined.

Question 3 of the Comment Form: *The scope of this project includes:*

- *Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,*
- *Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and*
- *Addressing issues identified in FERC Order 693.*

Do you agree with this scope? If not, please explain in the comment area.

IESO commented:

The SDT should consider the term characteristics during the review of the standards. The following is an example of: PRC-019-1
R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation could be to define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions.

In other words, the terms "characteristics" and "setpoints/settings" are presented in the requirements without clearly clarifying the meaning of the terms. “Characteristic” could mean something like a Generator capability curve (or any operating curve for that matter or nomograms) where the operations are defined by a “bounded region of operation” as such and is kind of “analog” in nature. “Setpoint/Setting” on the other hand could be something like a Generator Under-frequency trip setting where there are “set-points” for tripping – kind of “digital” in nature. Is this what the SDT means by these terms. Please clarify. As the standards are reviewed, there are specific questions that need to be addressed such as: MOD-025-1
R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output?
Also, What will define the need to revisit this when equipment changes occur? In addition, the SDT should consider additional field tests for all the changes associated with the revised standard.

IRC-SRC and ISO-NE commented:

The SDT should consider the term characteristics during the review of the standards. Sections below are identified as locations for clarification.
-PRC-019-1
R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation would be define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions. What is meant by characterisitics, if the characteristics are not defined as the setpoint? As the standards are reviewed, there are specific questions that need to be addressed such as:
MOD-025-1
R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output?

Also, What will define the need to revisit this when equipment changes occur?
The SDT should also identify a date for compliance for each of the requirements and measures. Here are a few examples:
-MOD-024-1
M1 & M3 - Will need to prescribed a date for compliance
-MOD-026-1
M3 - Will need to prescribed a date for compliance
-MOD-027-1
M1 & M3 - Will need to prescribed a date for compliance

FirstEnergy commented:

The project should account for potential regional differences. See comment on question # 5 below.

Question 5 of the Comment Form: *If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:*

FirstEnergy commented:

Not aware of existing, but potential for regional differences exist. The fill-in-the-blank needs to take into account regional differences such as summer or winter peaking conditions. The standard needs to address the main factor in generation capacity which is inlet water temperatures on once through cooling units and ambient temperature and humidity on cooling towers and combustion turbines.

Question 7 of the Comment Form: *If you have any other comments on this SAR that you haven’t already mentioned above, please provide them here:*

AEP commented:

Please transmit to the Standard Drafting Team the following specific suggested revisions to MOD-025:

Key changes relate to FERC's requirement that regional "fill-in-the-blank" standards be rewritten as North American standards; these and other recommended changes are provided below:

A. Introduction

1. Title: Verification of Generator [ ] Reactive Power Capabilities

3. Purpose: To ensure that [ ] steady-state models used for assessing Bulk Electric System reliability reflect realistic/usable generator reactive power capabilities.

B. Requirements

R1. The North American Electric Reliability Corporation (NERC) shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.5. Information to be reported to Regional Reliability Organization (RRO):

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1. and at Minimum Real Power output levels of generators. Net capabilities should be reported at the low- and high-voltage terminals of generator step-up (GSU) transformers.

R1.5.3. Verified Real and Reactive Power of auxiliary loads fed from: (a) generator bus and (b) transmission system bus (listed separately).

R1.5.5. System bus voltages (as scheduled and as verified), generator bus voltage and generator hydrogen pressure.

R1.5.6. In-service transformer taps setting and impedance (including base quantities).

R1.6. Requirement that sanity checks (or analysis) be used to ensure consistency/accuracy of reactive power capabilities obtained via measurement.

R2. The RRO shall provide [ ] generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to ...

R3. The Generator Owner shall follow NERC's procedures for verifying and reporting to RRO generator gross and net Reactive Power capabilities per R1.

C. Measures

M2. The RRO shall have written evidence that [ ] procedures...

M3. The Generator Owner shall have written evidence it provided verified information of its generator gross and net Reactive Power capabilities, consistent with NERC's procedures.

D. Compliance

This section should be revised to recognize that the procedures for generator Reactive Power capability verification will be written by NERC as a continent-wide standard. AEP recommends that Ape’s Circular Letter OP-G-CL-011 (Reactive Capability Testing of Generators), developed over nearly two decades of testing experience and advocacy within the former ECAR region, be used as a reference in drafting this standard.

ATC LLC commented:

The SAR includes language requiring the SDT to identify any generators that should be exempt from compliance. There are many standards both under this project and others (such as Project 2007-01) that need to consider applicability based on generator size and/or voltage. If these standards remain separate, this requirement will either force

needless repetition of the same language in many standards, or there is a distinct possibility that differences will develop among the exemptions, making it very difficult for generator owners to know which of their generators are covered by which standards. I suggest there should be a global definition of minimum generator size to which all NERC Reliability Standards apply, much like the global definition of Bulk Electric System. To start the discussion let me suggest "generators with a net electrical output or 20 MW or greater, connected through a step-up transformer with a high voltage rating of 100 kV or higher."
The wording in the third bullet point for MOD-024-1 and MOD-025-1 in the Detail Description should be changed from "Consider Requiring" to just "Require".

Standard Authorization Request Form

Title of Proposed Standard	Generator Verification (Project 2007-09)
Request Date	April 3, 2007
Modified Date	June 14, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: Bob Millard	☒	New Standards
Primary Contact: Bob Millard	☒	Revision to existing Standards:
Telephone: (708) 588-9886 Fax:	☐	Withdrawal of existing Standard
E-mail: bob.millard@rfirst.org	☐	Urgent Action

116-390 Village Boulevard, Princeton, New Jersey 08540-5721
Phone: 609.452.8060 ▪ Fax: 609.452.9550 ▪ www.nerc.com

Purpose

The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

New standards to be finalized as part of this project are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-026 —Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

Standards to be revised as part of this project are:

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

Industry Need

All six of the standards included in this project address generator verifications needed to support bulk power system reliability. All six of the standards included in this project were originally "Phase III & IV Planning Measures" that were translated into new or proposed standards as part of the Version 0 translation effort. Stakeholders have already agreed that there is a reliability-related need for each of these standards as part of the work performed in association with the Phase III & IV Modeling SAR. In addition, each of the standards included in this project has some "fill-in-the-blank" requirements assigned to the Regional Reliability Organization that need to be replaced with more specific "continent-wide" requirements before the standards are approved.

Specifically:

- MOD-024-1 and MOD-025-1 were approved by the NERC Board of Trustees but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization (MOD-024-1 and MOD-025-1 require generator owners to verify the generator's gross and net real and reactive power capability using an RRO established procedure).

- PRC-019-1, PRC-024-1, MOD-026-1 and MOD-027-1 are draft standards that were developed under the Phase III & IV Modeling SAR that have not been presented to the NERC Board of Trustees yet. These four standards contain "fill-in-the-blank" requirements assigned to the Regional Reliability Organization (RRO) which were appropriate when the standards were initially drafted but are not appropriate under current requirements for approval of enforceable standards. Work on these standards to remove the "fill-in-the-blank" requirements under the Phase III & IV Modeling SAR is not authorized and therefore cannot be completed under the Phase III & IV Modeling SAR because the modifications needed to make the standards enforceable are outside the scope of the original Phase III & IV SARs. To properly complete these standards, a new SAR is needed and the prior SAR need to be terminated (termination of the Phase III & IV Modeling SAR will be performed outside the work of this SAR).
    - This set of standards includes verification of the generator's excitation system; verification of the generator's frequency response; verification that the generator can remain connected during specified voltage and frequency excursions; and verification that the generator's voltage regulator controls and limit functions have been coordinated with the generator's capabilities and protective relays.
    - The field test for this set of standards has shown that a standard can be written to support these verifications.

Brief Description

The scope of this project includes:

- modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Rules of Procedure,
- replacing the "fill-in-the-blank" requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners or operators of the bulk power system, ~~and~~
- considering and addressing issues identified in FERC orders, including the modifications to MOD-024-1 and MOD-025-1 as proposed in FERC Order 693, and~~.~~
- considering and addressing issues identified during Phase III & IV field testing.

Detailed Description
The standards drafting team (SDT) will bring the six standards into conformance with the latest version of NERC's Reliability Standards Development Procedure and the ERO Rules of Procedure. In addition, the S~~T~~DT will consider and address all applicable FERC Orders~~,~~ including but not limited to FERC Order 693, the field test results from the Phase III & IV field testing, issues raised by the industry during the posting of the SAR for Project 2007-09 Generator Verification identified in Attachment 1, and the following proposed changes for each of the six standards in this set of standards:

Draft PRC-019-1
- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generators~~ owners~~ that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft PRC-024-1
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification that generators will remain connected during specified system frequency and voltage excursions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a requirement for the Transmission Owner and Generator Owner to coordinate protection systems
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

MOD-024-1:
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with verification of generator gross and net real power capability
    - Consider requiring the generator owner to document the test conditions and

    - the relationships between test conditions and generator output
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

MOD-025-1:
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with verification of generator gross and net Reactive Power capability
    - Consider requiring verification of reactive power capability at multiple points over a unit's operating range
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft MOD-026-1
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with generator excitation system functions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Draft MOD-027-1
- Revise the purpose statement to include the reliability-related benefit of the standard
- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard
- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of 'continent-wide' criteria for verification of models and data associated with generator unit frequency response

- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a 'violation risk factor' and a 'time horizon' for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the 'levels of non-compliance' with 'violation severity levels'

Reliability Functions

The Standard Drafting Team will Consider Applicability to All Functional Entities *(Check box for each one that may apply.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒~~☐~~	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.Yes
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure. Yes
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
Phase III&IV Modeling	This SAR dated 11/17/04 initiated work on all six standards, two of which have been approved by the NERC BOT and four of which are still in draft phase, as referenced above above. The SDT working on the four draft standards will be terminated and undertaken by the new SDT for this SAR.

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

Issues Raised by Industry During 1st Posting of SAR for Project 2007-09 Generator Verification Which are Outside the Responsibility of the SAR Drafting Team

Question 2 of the Comment Form: *Two of the standards (MOD-024 and MOD-025) associated with this SAR had already been approved by the NERC Board of Trustees, but are "pending" with FERC because they include "fill-in-the-blank" requirements assigned to the Regional Reliability Organization. These standards must be revised to remove the fill-in-the-blank characteristics before they can become mandatory and enforceable. The intent of MOD-024 and MOD-025 is to ensure that accurate information on generator gross and net real and reactive power capability is available for the steady-state models used to assess bulk electric system reliability. To be enforceable, these standards need to be revised. Do you agree that there is a reliability-related need to revise these standards to support accurate modeling?*

Ameren commented:

With regards to the scope of MOD-025, it should not be necessary to include a blanket requirement for verification of reactive power capability at multiple points for all generators. However, should a generator frequently have difficulty reaching its stated reactive power output, additional testing requirements for that generator would be indicated.

FirstEnergy commented:

The present legacy document ECAR Document 4 details the testing and is sufficient to cover the present accurary for a regional basis. The standards if spread to a national level will need to look at the difference between summer peaking regions and winter peaking. Presently the testing in RFC follows ECAR Document 4 which corrects the testing for average ambient conditions which is left up to the discretion of the testing personnel. The temperature conditions of the water inlet or ambient air needs to be defined.

Question 3 of the Comment Form: *The scope of this project includes:*

- *Modifying the six standards associated with this project so they conform to the latest version of NERC's Reliability Standards Development Procedure and the ERO Sanction Guidelines,*
- *Replacing the fill-in-the-blank requirements assigned to the Regional Reliability Organization with requirements that can be applied on a continent-wide basis and are assigned to users, owners, or operators of the bulk power system, and*
- *Addressing issues identified in FERC Order 693.*

Do you agree with this scope? If not, please explain in the comment area.

IESO commented:

The SDT should consider the term characteristics during the review of the standards. The following is an example of: PRC-019-1
R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation could be to define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions.

In other words, the terms "characteristics" and "setpoints/settings" are presented in the requirements without clearly clarifying the meaning of the terms. “Characteristic” could mean something like a Generator capability curve (or any operating curve for that matter or nomograms) where the operations are defined by a “bounded region of operation” as such and is kind of “analog” in nature. “Setpoint/Setting” on the other hand could be something like a Generator Under-frequency trip setting where there are “set-points” for tripping – kind of “digital” in nature. Is this what the SDT means by these terms. Please clarify. As the standards are reviewed, there are specific questions that need to be addressed such as: MOD-025-1
R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output?
Also, What will define the need to revisit this when equipment changes occur? In addition, the SDT should consider additional field tests for all the changes associated with the revised standard.

IRC-SRC and ISO-NE commented:

The SDT should consider the term characteristics during the review of the standards. Sections below are identified as locations for clarification.
-PRC-019-1
R2.1.2 & R2.1.5 - How to define characteristics? A common interpretation would be define characteristics as the "setpoints" for the controllers. However, this does not appear to be the case as in other requirements they request "setpoints" as is shown in R2.1.6. MOD-026-1 appears to address this but refers to the excitation system functions. What is meant by characterisitics, if the characteristics are not defined as the setpoint? As the standards are reviewed, there are specific questions that need to be addressed such as:
MOD-025-1
R1.5.3 - Is this individual loads, or is this an overall value for the total auxiliary loads running at full station output?

Also, What will define the need to revisit this when equipment changes occur?
The SDT should also identify a date for compliance for each of the requirements and measures. Here are a few examples:
-MOD-024-1
M1 & M3 - Will need to prescribed a date for compliance
-MOD-026-1
M3 - Will need to prescribed a date for compliance
-MOD-027-1
M1 & M3 - Will need to prescribed a date for compliance

FirstEnergy commented:

The project should account for potential regional differences. See comment on question # 5 below.

Question 5 of the Comment Form: *If you are aware of any regional variances that will be needed as a result of this project, please identify the Regional Variance:*

FirstEnergy commented:

Not aware of existing, but potential for regional differences exist. The fill-in-the-blank needs to take into account regional differences such as summer or winter peaking conditions. The standard needs to address the main factor in generation capacity which is inlet water temperatures on once through cooling units and ambient temperature and humidity on cooling towers and combustion turbines.

Question 7 of the Comment Form: *If you have any other comments on this SAR that you haven’t already mentioned above, please provide them here:*

AEP commented:

Please transmit to the Standard Drafting Team the following specific suggested revisions to MOD-025:

Key changes relate to FERC's requirement that regional "fill-in-the-blank" standards be rewritten as North American standards; these and other recommended changes are provided below:

A. Introduction

1. Title: Verification of Generator [ ] Reactive Power Capabilities

3. Purpose: To ensure that [ ] steady-state models used for assessing Bulk Electric System reliability reflect realistic/usable generator reactive power capabilities.

B. Requirements

R1. The North American Electric Reliability Corporation (NERC) shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.5. Information to be reported to Regional Reliability Organization (RRO):

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1. and at Minimum Real Power output levels of generators. Net capabilities should be reported at the low- and high-voltage terminals of generator step-up (GSU) transformers.

R1.5.3. Verified Real and Reactive Power of auxiliary loads fed from: (a) generator bus and (b) transmission system bus (listed separately).

R1.5.5. System bus voltages (as scheduled and as verified), generator bus voltage and generator hydrogen pressure.

R1.5.6. In-service transformer taps setting and impedance (including base quantities).

R1.6. Requirement that sanity checks (or analysis) be used to ensure consistency/accuracy of reactive power capabilities obtained via measurement.

R2. The RRO shall provide [ ] generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to ...

R3. The Generator Owner shall follow NERC's procedures for verifying and reporting to RRO generator gross and net Reactive Power capabilities per R1.

C. Measures

M2. The RRO shall have written evidence that [ ] procedures...

M3. The Generator Owner shall have written evidence it provided verified information of its generator gross and net Reactive Power capabilities, consistent with NERC's procedures.

D. Compliance

This section should be revised to recognize that the procedures for generator Reactive Power capability verification will be written by NERC as a continent-wide standard. AEP recommends that Ape's Circular Letter OP-G-CL-011 (Reactive Capability Testing of Generators), developed over nearly two decades of testing experience and advocacy within the former ECAR region, be used as a reference in drafting this standard.

ATC LLC commented:

The SAR includes language requiring the SDT to identify any generators that should be exempt from compliance. There are many standards both under this project and others (such as Project 2007-01) that need to consider applicability based on generator size and/or voltage. If these standards remain separate, this requirement will either force needless repetition of the same language in many standards, or there is a distinct possibility that differences will develop among the exemptions, making it very difficult for generator owners to know which of their generators are covered by which standards. I suggest there should be a global definition of minimum generator size to which all NERC Reliability Standards apply, much like the global definition of Bulk Electric System. To start the discussion let me suggest "generators with a net electrical output or 20 MW or greater, connected through a step-up transformer with a high voltage rating of 100 kV or higher."

The wording in the third bullet point for MOD-024-1 and MOD-025-1 in the Detail Description should be changed from "Consider Requiring" to just "Require".

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

July 17, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Nomination Periods Open for Five New Drafting Teams

The Standards Committee announces the following standards actions:

Project 2007-04 — Certifying System Operators SAR Drafting Team (July 17–30, 2007)

The Standards Committee is seeking industry experts to serve on the Certifying System Operators SAR Drafting Team. The drafting team will work on the modification of the following standard:

PER-003 — Operating Personnel Credentials

If you are interested in serving on this SAR drafting team, please complete this nomination form and return it to sarcomm@nerc.net by July 30, 2007 with "SO Certification SAR DT" in the subject line. For questions, please contact Linda Clarke at 610-310-7210 or linclrke@msn.com.

Project 2007-05 — Balancing Authority Controls SAR Drafting Team (July 17–30, 2007)

The Standards Committee is seeking industry experts to serve on the Balancing Authority Controls SAR Drafting Team. The drafting team will work on modifications to the following standards:

- BAL-002 — Disturbance Control Performance
- BAL-004 — Time Error Correction
- BAL-005 — Automatic Generation Control
- BAL-006 — Inadvertent Interchange

If you are interested in serving on this SAR drafting team, please complete this nomination form and return it to sarcomm@nerc.net by July 30, 2007 with "BA Controls SAR DT" in the subject line. For questions, please contact Linda Clarke at 610-310-7210 or linclrke@msn.com.

Project 2007-09 — Generator Verification Standard Drafting Team (July 17–30, 2007)

The Standards Committee is seeking industry experts to serve on the Generator Verification Standard Drafting Team. If you are interested in serving on this team, please complete this nomination form and return it to sarcomm@nerc.net with "Gen Verification SDT" in the subject line by July 30, 2007. For questions, please contact David Taylor at 609-651-5089 or david.taylor@nerc.net.

The drafting team will work on finalizing the following Phase III & IV standards:

- PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024 — Generator Performance during Frequency and Voltage Excursions
- MOD-026 — Verification of Models and Data for Generator Excitation System Functions
- MOD-027 — Verification of Generator Unit Frequency Response

The drafting team will also work on revising two existing standards that were not approved by the FERC because of their "fill-in-the-blank" elements:

- MOD-024 — Verification of Generator Gross and Net Real Power Capability
- MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

Project 2007-12 — Frequency Response Standard Drafting Team (July 17–30, 2007)
The Standards Committee is seeking industry experts to serve on the Frequency Response Standard Drafting Team. The drafting team will work to develop a standard that requires entities to provide data so that Frequency Response in each of the Interconnections can be modeled, and the reasons for the decline in Frequency Response can be identified.

If you are interested in serving on this standard drafting team, please complete this nomination form and return it to sarcomm@nerc.net by July 30, 2007 with "FR SDT" in the subject line. For questions, please contact Linda Clarke at 610-310-7210 or linclrke@msn.com.

Project 2007-23 — Violation Severity Levels Drafting Team (July 17–30, 2007)
The Standards Committee is seeking industry experts to serve on the Violation Severity Levels SAR Drafting Team. The drafting team will work to achieve consensus on a set of criteria for assigning Violation Severity Levels, and will work (with other existing drafting teams) to replace "Levels of Non-compliance" with "Violation Severity Levels" in the 83 standards approved by the FERC. FERC directed NERC to replace "Levels of Non-compliance" with "Violation Severity Levels' so that the ERO's Sanctions Guidelines can be used as intended.

If you are interested in serving on this standard drafting team, please complete this nomination form and return it to sarcomm@nerc.net by July 30, 2007 with "VSL DT" in the subject line. For questions please contact Al Calafiore at 678-524-1188 or al.calafiore@nerc.net or Stephen Crutchfield at 609-651-9455 or stephen.crutchfield@nerc.net.

Standards Development Process
The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Nomination Form for Generator Verification Standard Drafting Team (Project 2007-09)

Please return this form to sarcomm@nerc.net by **July 30, 2007** with the words "**Gen Verification SDT**" in the subject line. If you have questions please contact Dave Taylor at david.taylor@nerc.net or by telephone at 609-651-5089.

Name:

Organization:

Address:

Office Telephone:

E-mail:

Please briefly describe your experience and qualifications to serve on the Generator Verification Standard Drafting Team. Prefer experience in developing generator models, in verifying generator capabilities, or in coordinating generator protection with transmission protection. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):		**I represent the following Industry Segment(s) (check all that apply):**
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs, ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations and Regional Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Monitor	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Authority	☐ Purchasing-selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator	☐ Reliability Coordinator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the Functional Model, which is downloadable from the following Web site: http://www.nerc.com/~filez/functionalmodel.html

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR authorized by Standards Committee for development as a reliability standard July 12, 2007.

Standard Drafting Team appointed by Standards Committee September 11, 2007.

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard and includes requirements with violation risk factors, time horizons and measures; additional compliance elements will be added later. This first posting of the standard is for a 45-day comment period from February 17 through April 2, 2009.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and second version of standard.	May 4, 2009
2. Post response to comments and request authorization to ballot the revised standard.	To be determined
3. Conduct initial ballot.	To be determined
4. Post response to comments.	To be determined
5. Conduct recirculation ballot.	To be determined
6. BOT adoption.	To be determined
7. File with regulatory authorities.	To be determined

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**

2. **Number:** PRC-024-1

3. **Purpose:** Ensure that generator frequency and voltage protective relays[1] are set to support transmission system stability during voltage and frequency excursions.

4. **Applicability**

   4.1. Functional entities:

   4.1.1 Generator Owners

   4.2. Facilities:

   4.2.1 Each generating unit (with installed voltage or frequency protective relays) greater than 20 MVA connected to the Bulk Electric System (BES).

   4.2.2 Each unit (with installed voltage or frequency protective relays) at generating plants/facilities consisting of multiple units with total generation > 75 MVA (gross aggregate nameplate rating) at the point of interconnection to the BES.

5. **Effective Dates:** The standard is effective the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC BOT adoption in those jurisdictions where regulatory approval is not required).

   Each Generator Owner's unit with installed voltage or frequency protective relays shall be compliant with the standard based on the following phased implementation schedule:

   5.1. No less than 33% of a Generator Owner's units shall be fully compliant with the standard within 1 year of the effective date of the standard.

   5.2. No less than 66% of a Generator Owner's units shall be fully compliant with the standard within 2 years of the effective date of the standard

   5.3. No less than 100% of a Generator Owner's units shall be fully compliant with the standard within 3 years of the effective date of the standard

A. Requirements

R1. Each Generator Owner shall set its installed generator frequency protective relaying not to trip during the following frequency-related operating conditions unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5: *(Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA) (Time Horizon – Operations Planning)*

R1.1. When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive.

R1.2. During the off-normal frequency excursions specified in PRC-024-1 Attachment 1.

R1.3. Instantaneous underfrequency relay trip setting shall be set no higher than 57.8 Hz.

R1.4. Instantaneous overfrequency relay trip settings shall be set no lower than 62.2 Hz.

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[1] Includes voltage and frequency protective functions for discrete relays, multi-function protective devices, voltage regulators, etc.

R2. Each Generator Owner shall set its installed generator over and under voltage (including volts per hertz relays evaluated at nominal frequency) protective relays not to trip during the steady-state and voltage-related operating conditions as follows unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5 of this standard: *(Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA) (Time Horizons – Operations Planning)*

R2.1. When operating within 95% to 105% of rated generator terminal voltage.

R2.2. During the transient voltage excursions measured at the point of interconnection to the BES as specified in PRC-024-1 Attachment 2. The following generator protective relaying settings are acceptable:

R2.2.1. For three-phase transmission system zone one faults with Normal Clearing, relaying may be set based on actual fault clearing times, but not greater than nine cycles.

R2.2.2. Relaying may be set to meet a shorter voltage ride through duration curve as specified by the Transmission Planner based on the location specific voltage recovery characteristics.

R2.2.3. Relaying may be set to trip a generator after fault initiation if this action is intended as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).

R2.2.4. Relaying may be set to trip a generator if clearing a system fault necessitates disconnecting the generator.

R3. Each Generator Owner shall provide to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners (that monitor or model the associated unit) its generator protection trip settings as specified by Requirement R1 and Requirement R2 within 30 calendar days of any change to those trip settings. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*

R4. Each Generator Owner shall provide to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners (that monitor or model the associated unit), its generator protection trip settings as specified by Requirement R1 and Requirement R2 within 30 calendar days of a written request for the data. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*

R5. If an existing generator unit[2] cannot meet either Requirement R1 or Requirement R2 due to equipment limitations, such as manufacturer warranty requirements or limitations that endanger the equipment according to published manufacturer instructions, (Protection System excluded), the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation. *(Violation Risk Factors: Medium - Units >100 MVA; Lower - Units ≤100 MVA) (Time Horizon – Operations Planning)*

[2] Including generators under construction, generators with an executed interconnection agreement or Power Purchase Agreement, or generators with an executed equipment purchase contract and scheduled delivery within 2 years of the effective date of the standard.

The exception for the equipment limitation shall expire coincident with either of the following conditions:

- The equipment causing the limitation is replaced with equipment that removes the technical limitation.
- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10%.

R6. The Generator Owner shall provide a written response within 90 calendar days of receipt of written comments from a Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner (that monitors or models the associated unit) regarding the equipment limitation. The response shall indicate whether a change will be made to the equipment limitation or if no change will be made to the equipment limitation, the reason why. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*

B. Measures

M1. Each Generator Owner shall have evidence such as setting sheets, calibration sheets, or other documentation, that generator frequency protective relays have been set in accordance with Requirement R1.

M2. Each Generator Owner shall have evidence such as setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies, that generator voltage protective relays have been set in accordance with Requirement R2.

M3. Each Generator Owner shall have evidence such as dated e-mails, mail receipts or other documentation that generator protective relay settings changes have been communicated to the entities listed in Requirement R3.

M4. Each Generator Owner shall have evidence such as dated e-mails, mail receipts, request received or other documentation that generator protective relay settings have been communicated to the entities listed in Requirement R4.

M5. Each Generator Owner of existing generators that are unable to comply with Requirements R1 or R2 due to equipment limitations (Protection System excluded) shall have evidence such as warranty agreements, insurance agreements, manufacturers documented limitations, engineering analysis or other documentation that explains the equipment limitation of the unit(s).

M6. Each Generator Owner shall have evidence such as dated copy, e-mail receipts or other evidence that it provided a written response to a commenting entity within 90 calendar days of receipt of comments.

C. Regional Variances

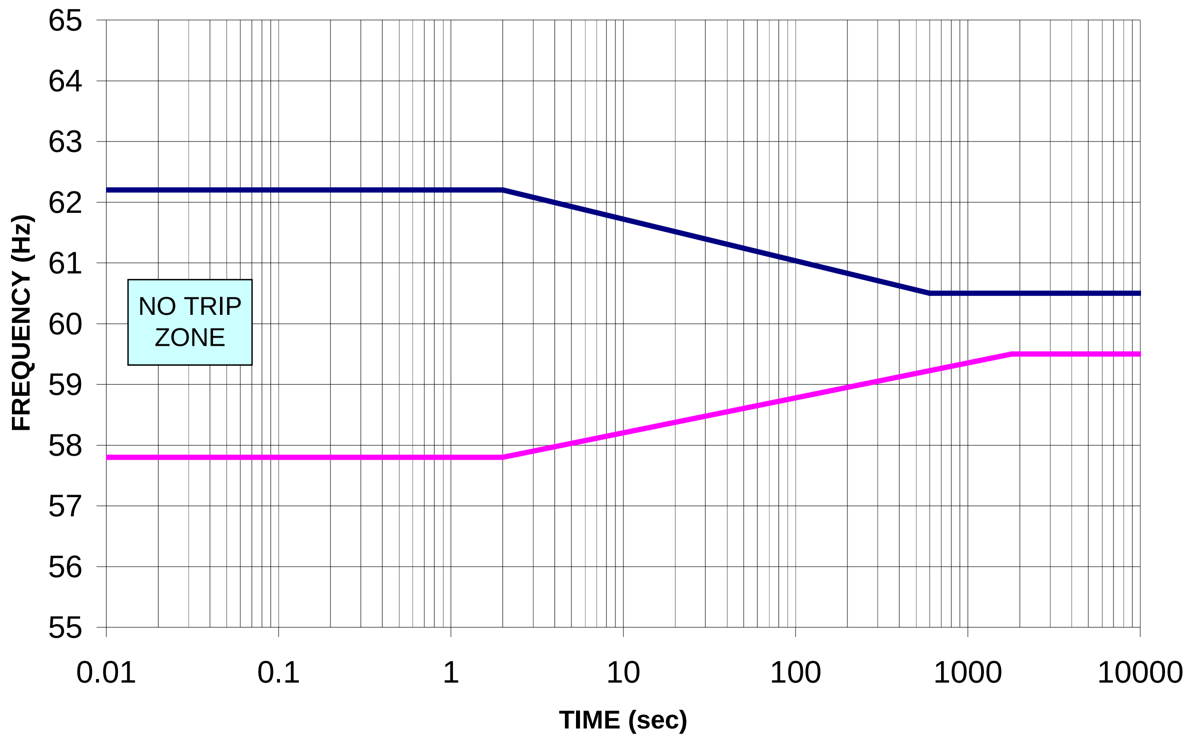
None

D. References

"The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

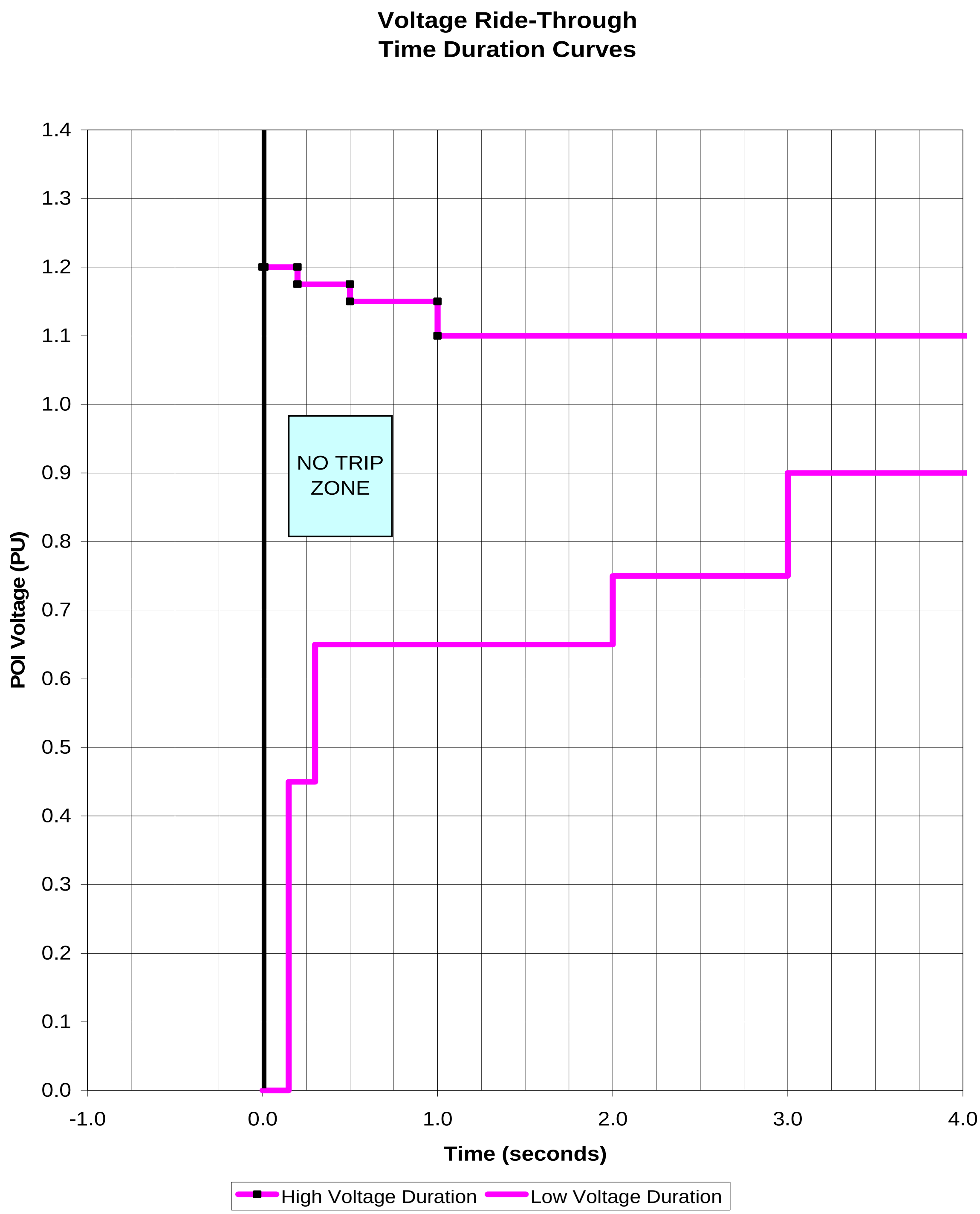
PRC-024-1 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Frequency (hertz)	62.2	60.5	57.8	59.5
Time (seconds)	0 to 2	600 to 10,000	0 to 2	1,800 to 10,000

PRC-024-1 — Attachment 2



The following data points would apply to this curve:

HVRT DURATION	
Time	Voltage
0.20	1.200
0.50	1.175
1.00	1.150
4.00	1.100

LVRT DURATION	
Time	Voltage
0.15	0.000
0.30	0.450
2.00	0.650
3.00	0.750
4.00	0.900

Voltage Ride-Through Curve Clarifications

1. The per unit voltage base for this curve is the nominal operating voltage as measured at the point of interconnection to the BES.
2. As long as the cumulative voltage duration at the point of interconnection with the BES is within the voltage boundaries of the curve, the generator voltage protective relaying will not trip the generator.
3. The curve depicted in this Attachment 2 assumes system frequency of 60 Hertz and all of the units connected to the same transformer are on line.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for the First Draft of PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings (Project 2007-09)

Please **DO NOT** use this form. Please use the **electronic comment form** located at the link below to submit comments on the proposed first draft of the Generator Verification standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings. Comments must be submitted by **April 2, 2009.** If you have questions please contact Harry Tom at harry.tom@nerc.net or by telephone at (860) 550-4157.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Background Information:

This comment form pertains to PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings. The Generator Verification Standard Drafting Team (Project 2007-09) is comprised of six standards, one of which is PRC-024-1. These standards were originally "Phase III & IV Planning Measures" that were translated into new or a proposed standard as part of the Phase III & IV Standard Drafting Team effort. Collectively they set forth requirements to:

- Ensure generator and generator ancillary equipment are accurately modeled.
- Generator Protective Relay systems are appropriately set to "ride through" voltage and frequency excursions and to coordinate with load shed programs.
- Establish a regular process of verifying actual generator performance capability through periodic testing.

Draft standards that were field tested in 2006–2007 and are to be finalized as part of this project are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Frequency and Voltage Protective Relay Settings

MOD-026 — Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

Standards to be revised as part of this project are:

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings was developed with consideration to key issues stated in the SAR:

- Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard

- Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of ‘continent-wide’ criteria for verification that generators will remain connected during specified system frequency and voltage excursions
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Add a requirement for the Transmission Owner and Generator Owner to coordinate protection systems
- Add a ‘violation risk factor’ and a ‘time horizon’ for each requirement
- Update all the compliance sections of the standard, including:
    - Update the compliance monitoring section to clarify that the regional entity will be the compliance monitor for the generator owner
    - Replace the ‘levels of non-compliance’ with ‘violation severity levels’

The SDT first considered the purpose of the standard as defined in the SAR, the verifiable and measurable quantities in PRC-024-1 to ensure that the generators would stay connected are the relay settings in the generator protective relay schemes. The SDT has therefore proposed that standard PRC-024-1 be based on generator relay setting and coordination requirements, such as the time durations associated with various levels of voltage or frequency excursions.

For frequency excursions, this would include turbine under frequency protection relays. It was assumed by the SDT that excitation controls and limiters are set such that generator protective relays that are implemented to protect against excessive rotor field and stator over currents would not trip the unit as a result of the proposed frequency excursion.

For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected. As such, dynamic simulations are not necessary to meet the requirements of the draft standard. The assessment of other generator protective relays that would require dynamic simulation to assess if they could ride through the proposed voltage excursion, such as generator backup over current or impedance, loss of field, are not within the scope of this draft standard.

In addition, the requirements are focused on the time immediately after a fault but before upsets to the auxiliary equipment could potentially cause the generator to trip.

The SDT next considered the “applicability”. Although the Generator Operator is the entity that can obtain the verified values of the relay settings, the Generator Owner is responsible for such settings.

In developing the proposed requirements, the SDT has reviewed the requirements of Regional Entities associated with potential voltage and frequency excursions, as well as simulated system responses to faults cleared with zone 1 and zone 2 distance relays. Understanding that some existing older generators were designed and constructed based on the then existing standards and may not be able to conform to the proposed new requirements, the SDT proposed that such limitations of existing generators be communicated to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit so that they be accounted for in the simulations of system responses. However, the generator will be required to conform to the standard if limitations are removed, for example, through equipment upgrades.

The following questions will assist the SDT in finalizing the development of PRC-024-1 Generator Frequency and Voltage Protective Relay Settings. For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. To improve this first draft of PRC-024-1 Generator Frequency and Voltage Protective Relay Settings, the SDT would appreciate responses to as many of these questions as you can answer.

1. The PRC-024-1 Standard is applicable to the Generator Owner as opposed to Generator Operator, do you agree? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

2. The SDT has established the Requirements in this Standard only for the setting of voltage and frequency generator protective relays. Do you agree? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

3. PRC-024-1 specifies the limits for generator protective system settings as defined in PRC-024-1 - Attachment 1 and PRC-024-1 - Attachment 2. Are there generating units in your fleet that are not capable of meeting the thresholds in these attachments due to turbine/generator equipment design limitations?

☐ Yes

☐ No

Comments:

If yes, please estimate the percentage and total MW capacity of your units that cannot meet the requirement.

Estimated percentage of units that can't meet thresholds due to design limitations:

Estimated total MW capacity of units that cannot meet the requirement:

4. The curve in PRC-024-1 - Attachment 2 was based upon analysis performed of simulated system disturbances. System voltage traces representative of several hundred disturbances were co-plotted on a voltage versus time graph. The voltage duration curve in this attachment is derived from these voltage traces. A margin was then applied to the voltage duration curve to account for unanticipated system conditions. The 9 cycle fault clearing time required by the FERC 661-A Order is incorporated into this curve. Given this background on the development of PRC-024-1 - Attachment 2, do you agree with the parameters of the curve? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

5. Coordination between UFLS programs and generator frequency tripping is especially a concern in islanded situations. Is the connection voltage of ≥100kV, the size threshold for generator units 20 MVA and greater and 75 MVA for multiple units at a single site, sufficient to address this concern? If not, please explain in the comment area.

☐ Yes

☐ No

Comments:

6. The SDT proposed a set of VRFs based on size delineation of units. Do you agree with this approach? Do you agree with the MVA levels? If you disagree with either the approach or the MVA levels, please explain in the comment area.

☐ Yes I agree with the approach

☐ No I disagree with the approach

Comments:

Do you agree with the MVA levels?

☐ Yes

☐ No

Comments:

7. If you are aware of any regional variances that would be required as a result of this standard please identify the regional variance here.

Regional Variance:

8. If you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify the conflict here.

Conflict:

9. Are there other improvements that the SDT should consider for this revision of PRC-024-1 that you haven't already identified in response to other questions? If yes, please provide in the comment area.

☐ Yes

☐ No

Comments:

Field Tested Version of PRC-024 Mapped to Proposed PRC-024-1, Generator Frequency and Voltage Protective Relay Settings

Field Tested Version of PRC-024	Comment	Proposed PRC-024-1
2. Number: PRC-024-0	Proposed standard will only cover PRC-024-0 content and will not be merged with any other standard	**2. Number:** PRC-024-1
1. Title: Generator Performance During Frequency and Voltage Excursions	Protective System has been added to reflect the scope of the related requirements in the proposed Standard	**1. Title:** Generator Frequency and Voltage Protective Relay Settings
3. Purpose: To ensure that generators remain connected to the electrical grid during voltage and frequency excursions and are not normally tripped manually or by preset protection schemes during frequency and voltage excursions.	The Purpose has been modified to specifically focus on the coordination of protection schemes.	**3. Purpose:** Ensure that generator frequency and voltage protective relays[1] are set to support transmission system stability during voltage and frequency excursions. [1] Includes voltage and frequency protective functions for discrete relays, multi-function protective devices, voltage regulators, etc.
4. Applicability: **4.1.** Regional Reliability Organizations. **4.2.** Generation Owners. **4.3.** Transmission Owners	Regional Reliability Organization and Transmission Owner applicability is eliminated. The Standard further specifies which facilities must comply.	**4. Applicability** **4.1.** Functional entities: **4.1.1** Generator Owners **4.2.** Facilities: **4.2.1** Each generating unit (with installed voltage or frequency protective relays) greater than 20 MVA connected to the Bulk Electric System, **4.2.2** Each unit (with installed voltage or frequency protective relays) at generating plants/facilities consisting of

Field Tested Version of PRC-024	Comment	Proposed PRC-024-1
		multiple units with total generation > 75 MVA (gross aggregate nameplate rating) at the point of interconnection to the Bulk Electric System
R1. The Regional Reliability Organization shall establish requirements for generators to remain connected during system frequency and voltage excursions expressed as a function of:	Regional applicability is eliminated and direct entity responsibility is defined	Requirements R1, & R2 define the verification and data reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Time duration in seconds or cycles **R1.2.** Amplitude or magnitude of the excursion **R1.3.** Relationship between time and amplitude or magnitude	The details of the frequency excursions are defined in **R1.1, R1.2, R1.3, R1.4,** and **Attachment 1-PRC-024-1**. The details of the voltage excursions are defined in **R2.1, R2.2, R2.2.1, R2.2.2, R2.2.3, R2.2.4,** and **Attachment 2-PRC-024-1**.	**R1**. Each Generator Owner shall set its installed generator frequency protective relaying not to trip during the following frequency-related operating conditions unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5: (Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA) (Time Horizon – Operations Planning) **R1.1.** When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive. **R1.2**. During the off-normal frequency excursions specified in PRC-024-1 Attachment 1. **R1.3**. Instantaneous underfrequency relay trip setting shall be set no higher than 57.8 Hz. **R1.4.** Instantaneous overfrequency relay trip settings shall be set no lower than 62.2 Hz. **R2.** Each Generator Owner shall set its installed generator over and under voltage (including volts per hertz relays evaluated at nominal frequency) protective relays not to trip during the steady-state and voltage-related operating conditions as follows unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5: (Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA)

Field Tested Version of PRC-024	Comment	Proposed PRC-024-1
		(Time Horizons – Operations Planning) **R2.1.** When operating within 95% to 105% of rated generator terminal voltage. **R2.2.** During the transient voltage excursions measured at the point of interconnection to the BES as specified in PRC-024-1 Attachment 2. The following generator protective relaying settings are acceptable: **R2.2.1** For three-phase transmission system zone one faults with Normal Clearing, relaying may be set based on actual fault clearing times, but not greater than nine cycles. **R2.2.2.** Relaying may be set to meet a shorter voltage ride through duration curve as specified by the Transmission Planner based on the location specific voltage recovery characteristics. **R2.2.3.** Relaying may be set to trip a generator after fault initiation if this action is intended as part of a Special Protection Scheme (SPS) or Remedial Action Scheme (RAS). **R2.2.4.** Relaying may be set to trip a generator if clearing a system fault necessitates disconnecting the generator.
R2. The Regional Reliability Organization shall establish and maintain requirements for generators to remain connected during frequency and voltage excursions. These requirements shall include:	Regional applicability is eliminated and direct entity responsibility is defined. Requirements **R1.2, R1.3,** and **R1.4** define the requirements for generator off-nominal frequency protective relay settings so that generating units remain connected during frequency excursions. Requirements **R2.2, R2.21, R2.2.2, R2.2.3** and **R2.2.4** define the requirements for	**R1.2**. During the off-normal frequency excursions specified in PRC-024-1 Attachment 1. **R1.3**. Instantaneous underfrequency relay trip setting shall be set no higher than 57.8 Hz. **R1.4.** Instantaneous overfrequency relay trip settings shall be set no lower than 62.2 Hz. **R2.2.** During the transient voltage excursions measured at the point of interconnection to the BES as specified in PRC-024-1 Attachment 2. The following generator protective relaying settings are acceptable: **R2.2.1** For three-phase transmission system zone one faults with Normal Clearing, relaying may be set based on actual fault clearing times, but not greater than nine cycles. **R2.2.2.** Relaying may be set to meet a shorter voltage ride through duration curve as specified by the Transmission Planner based on the location specific voltage recovery characteristics.

Field Tested Version of PRC-024	Comment	Proposed PRC-024-1
	generator under and over voltage protective relay settings so that generating units remain connected during voltage excursions.	**R2.2.3.** Relaying may be set to trip a generator after fault initiation if this action is intended as part of a Special Protection Scheme (SPS) or Remedial Action Scheme (RAS). **R2.2.4.** Relaying may be set to trip a generator if clearing a system fault necessitates disconnecting the generator.
R2.1. Coordination between the generator under frequency protection and the regional Under Frequency Load Shedding (UFLS) program.	During the drafting of this Standard, the Generator Verification Standard Drafting Team (GV SDT) maintained contact with the Under Frequency Load Shedding Standard Drafting Team (UFLS SDT) to ensure that the requirements of this Standard coordinated with the requirements being developed by the UFLS SDT. Requirements **R1, R1.1, R1.2, R1.3, R1.4, and Attachment 1-PRC-024-1** coordinate with the UFLS SDT effort.	**R1**. Each Generator Owner shall set installed generator frequency protective relaying not to trip during the following frequency-related operating conditions unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5: (Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA) (Time Horizon – Operations Planning) **R1.1.** When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive. **R1.2**. During the off-normal frequency excursions specified in PRC-024-1 Attachment 1. **R1.3**. Instantaneous underfrequency relay trip setting shall be set no higher than 57.8 Hz. **R1.4.** Instantaneous overfrequency relay trip settings shall be set no lower than 62.2 Hz.
R2.2. Coordination of generator protection, including back-up protection, with transmission Protection Systems.	The GV SDT created requirements for generator over and under voltage protective relay settings based on a voltage excursion defined by FERC Order 693 and low voltage excursion studies performed in WECC and SERC. Requirements **R2, R2.1, R2.2,**	**R2.** Each Generator Owner shall set installed generator over and under voltage (including volts per hertz relays evaluated at nominal frequency) protective relays not to trip during the steady-state and voltage-related operating conditions as follows unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5: (Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA) (Time Horizons – Operations Planning) **R2.1.** When operating within 95% to 105% of rated generator terminal voltage. **R2.2.** During the transient voltage excursions measured at the point of

Field Tested Version of PRC-024	Comment	Proposed PRC-024-1
	R2.2.1, R2.2.2, R2.2.3, R2.2.4, and Attachment 2-PRC-024-2 define these requirements. The GV SDT feels that coordination between the generator protection system and transmission protection system beyond that defined in this Standard is covered under **PRC-001 R3.**	interconnection to the BES as specified in PRC-024-1 Attachment 2. The following generator protective relaying settings are acceptable: **R2.2.1** For three-phase transmission system zone one faults with Normal Clearing, relaying may be set based on actual fault clearing times, but not greater than nine cycles. **R2.2.2.** Relaying may be set to meet a shorter voltage ride through duration curve as specified by the Transmission Planner based on the location specific voltage recovery characteristics. **R2.2.3.** Relaying may be set to trip a generator after fault initiation if this action is intended as part of a Special Protection Scheme (SPS) or Remedial Action Scheme (RAS). **R2.2.4.** Relaying may be set to trip a generator if clearing a system fault necessitates disconnecting the generator.
	New	**R3.** Each Generator Owner shall provide to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners (that monitor or model the associated unit) its generator protection trip settings as specified by Requirement R1 and Requirement R2 within 30 calendar days of any change to those trip settings. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)* **R4.** Each Generator Owner shall provide to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners (that monitor or model the associated unit) its generator protection trip settings as specified by Requirement R1 and Requirement R2 within 30 calendar days of a written request for the data. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*
R3. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the regional requirements established in accordance with R1 and R2.	Regional Reliability Organization applicability is eliminated and direct entity responsibility is defined	**R5**. If an existing generator unit[2] cannot meet either Requirement R1 or Requirement R2 due to equipment limitations, such as manufacturer warranty requirements or limitations that endangers the equipment according to published manufacturer instructions, (Protection System excluded), the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation

Field Tested Version of PRC-024	Comment	Proposed PRC-024-1
	R5 defines the criteria for exceptions from the frequency and voltage requirements and the process to use for reporting this to the Reliability Coordinators, Planning Coordinators, Transmission Operators, and Transmission Planners. **R6** defines the process for the Generator Owner to respond to comments on the notification of exception.	once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation. *(Violation Risk Factors: Medium - Units >100 MVA; Lower - Units ≤100 MVA) (Time Horizon – Operations Planning)* The exception for the equipment limitation shall expire coincident with either of the following conditions: • The equipment causing the limitation is replaced with equipment that removes the technical limitation. • The equipment causing the limitation is modified or upgraded resulting in an increase of nameplate capacity rating greater than 10%. [2] Including generators under construction, generators with an executed interconnection agreement or Power Purchase Agreement, or generators with an executed equipment purchase contract and scheduled delivery within 2 years of the effective date of the standard. **R6**. The Generator Owner shall provide a written response within 90 calendar days of receipt of written comments from a Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner (that monitors or models the associated unit) regarding the equipment limitation. The response shall indicate whether a change will be made to the equipment limitation or if no change will be made to the equipment limitation, the reason why. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*
R4. The Regional Reliability Organization shall establish and maintain a procedure for handling variances (i.e., different criteria or methods) from the Regional Reliability Organization's requirements established in R1 and R2, including steps for requesting and approving such variances.	Regional Reliability Organization applicability is eliminated and direct entity responsibility is defined. For the low voltage portion of the **Attachment 2-PRC-024-1**, **R2.2.2** allows the Transmission	**R2.2.2.** Relaying may be set to meet a shorter voltage ride through duration curve as specified by the Transmission Planner based on the location specific voltage recovery characteristics.

Field Tested Version of PRC-024	Comment	Proposed PRC-024-1
	Planner to modify the shape of the curve based on location-specific breaker clearing time and voltage recovery characteristics.	
R5. The Regional Reliability Organization shall provide documentation of its excursion requirements, exemptions, and variance procedure to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval.	Regional Reliability Organization applicability is eliminated. Since the excursion requirements, exemptions and variance procedures are defined in the Standard, there are no requirements for communication to applicable entities.	This is not addressed by any requirement of the proposed Standard because it is no longer applicable.
R6. The Regional Reliability Organization shall, at least every five years, review and, as necessary, update its requirements, exemption criteria, and variance procedure.	Regional Reliability Organization applicability is eliminated. Since the excursion requirements, exemptions and variance procedures are defined in the Standard, the method for making modifications involves implementing the NERC SAR process.	This is not addressed by any requirement of the proposed Standard because it is no longer applicable.
R7. Generator Owners and Transmission Owners shall comply with the regional requirements for coordination of generator protection defined in R2 and any approved variances	Transmission Owner applicability is eliminated. The requirement for a Generator Owner to comply with the requirements in this Standard is implicit in being an applicable entity.	This is addressed by the Applicability section of the proposed Standard.

Standards Announcement

Comment Periods Open
February 17 – April 2, 2009

Now available at: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Two Proposed Standards for Project 2007-09 — Generator Verification

The Generator Verification Standard Drafting Team (Project 2007-09) has posted drafts of two proposed standards for 45-day comment periods. Mapping documents that compare these standards with field-tested versions are also posted. The comment periods are now **open until 8 p.m. EDT on April 2, 2009**. Please use the electronic forms (see links below) to submit comments. If you experience any difficulties in using the electronic forms, please contact Lauren Koller at 609-524-7047. Off-line, unofficial copies of the comment forms are posted on the project page: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

Electronic comment form:
https://www.nerc.net/nercsurvey/Survey.aspx?s=aaa41c53fb80462e8783344cd70f6ce0

Note: the drafting team will hold a WebEx to explain the concepts in proposed standard PRC-024-1 on February 26 from 2 p.m. to 4 p.m. EST. More information about the WebEx will be sent in a separate announcement.

MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions

Electronic comment form:
https://www.nerc.net/nercsurvey/Survey.aspx?s=7b8a364e930f4c1a87a792881c9b94dd

Background

Project 2007-09 includes six standards to address generator verifications needed to support bulk power system reliability – four proposed standards and revisions to two existing standards. The purpose of the project is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

More information is available on the project Web page:
http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (44 Responses)
Name (31 Responses)
Organization (31 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
Contact Organization (13 Responses)
Question 1 (41 Responses)
Question 1 Comments (44 Responses)
Question 2 (42 Responses)
Question 2 Comments (44 Responses)
Question 3 (31 Responses)
Question 3 Comments (44 Responses)
Question 3 Comments (44 Responses)
Question 4 (39 Responses)
Question 4 Comments (44 Responses)
Question 5 (38 Responses)
Question 5 Comments (44 Responses)
Question 6 (38 Responses)
Question 6 Comments (44 Responses)
Question 6 (34 Responses)
Question 6 Comments (44 Responses)
Question 7 (0 Responses)
Question 7 Comments (44 Responses)
Question 8 (0 Responses)
Question 8 Comments (44 Responses)
Question 9 (38 Responses)
Question 9 Comments (44 Responses)

Individual
Jinhui Zhang
Converteam Naval Systems Inc.
No
I believe it should be applicable to both.
Yes
No
please see my further comments on this.
No
Yes I agree with the approach
Yes
Yes
0. (Overall) This is a good document that has good background study and contains a lot of expertise; 1. (Voltage definition inconsistency)In the LVRT curves, it talks about the voltage at

the point of interconnection. However, in R2.1 it uses voltage at the generator terminals. I think there is a little inconsistency between these two. It would be good to just use one of them, preferably the former one. The reason is that different generator plants might have different impedance between the generator terminals and the points of interconnection, so defining the voltage at the terminals poses a little unfairness. Another part of the reason is that for transmission protection purpose, it should ends at the point of interconnection. 2. (Voltage range inconsistency)The voltage range is 0.9-1.1pu in the VRT curve, but it says 0.95-1.05 in R2.1. It would be good to make it consistent. 3. (Date point missing) In the table supporting the VRT curves, the 0.95 and 1.05pu data are missing. 4. (Priority) WECC and MRO have different VRT curves. Which one will override which one at the end? Will the NERC PRC-024 take priority than the Regional Entities? 5. Was reactive power support during faults considered in the draft group? Will it be required in the future? Thanks
Individual
Jianmei Chai
Consumers Energy Company
Yes
Yes
No
Consumers Energy doesn't have generating units that cannot meet the thresholds. However, we would like to offer the following comments: The Standards Drafting Team should be congratulated for the excellent curves in Attachment 1. A review of our fleet which contains units of several vintages, manufactured by General Electric, Westinghouse, Siemens, and Allis-Chalmers, shows that turbine-generators from all of these manufacturers comply with these curves. To assist Generator Owners and Compliance Auditors, the SDT should furnish mathematical formulae for the "slanted lines" in the curves. Should a Generator Owner elect to set an underfrequency relay at 120 seconds and 59.1 Hz, there might be uncertainty or disagreement about compliance, depending upon how the interpolation of the graph is viewed. Interpolation from a semi-log plot is often not easy. This uncertainty can and should be eliminated by including the two formulae in Attachment 1.
Yes
Yes
We believe this is sufficient to address the concern if this picks up the wind farms that are a growing part of generating capacity.
Yes I agree with the approach
Yes
No.
No.
Yes
Please see comments on Question 3.
Group
Entergy Fossil Operations
Stan Jaskot
Entergy Fossil Operations
Yes
Generator Owner is responsible for the maintenance of the facility. Relay settings are a Generator Owner function.
No
I disagree in principle that NERC is dictating how generator protective relays are set. These relays are set to protect the generation equipment and ensure long term reliability of the unit. Dictating settings which enhances ride through capability ensure short term reliability and can hurt long term reliability. If this if force upon us, I agree with only addressing the voltage and frequency generator protective relays.
No
Yes

I do not know enough about this to comment either way
Yes
Yes I agree with the approach
Yes
Yes
Do away with this standard.
Group
NERC System Protection and Control Subcommittee (SPCS)
John Ciufo - SPCS
Hydro One
Yes
No
PRC-024 should only apply to non-synchronous machines. The SPCS believes that coordination of synchronous generator voltage and frequency protective relays with transmission relays should not be addressed in PRC-024. An effort is underway to address coordination of generator voltage and frequency protective relay settings with transmission protection systems either by modifications to PRC-001 or the development of a new SAR to address coordination requirements. SPCS is preparing a Technical Reference paper on such coordination that is expected to be completed in June, 2009. Generator voltage and frequency protective relays are included in that that paper. The purpose as stated in the SAR is "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The Standard will not accomplish its stated purpose by limiting requirements to generator protective relays alone. In fact it may actually have the exact opposite consequence. Undervoltage relays are not usually set on most synchronous generators. When undervoltage relays are applied, IEEE C37.102 recommends alarm rather than trip. The more likely cause for the loss of a generator due to a dip in voltage is from the loss of equipment on the auxiliary bus. This was the cause sited for a well documented event on March 27, 1994 losing all generating units at Cinergy's Gibson Station. Other events since 1994 were also due to tripping of generators due to loss of auxiliary busses caused by voltage dips from system faults. In fact, the Standard may result in the unintended consequence of reducing reliability. Many generator owners may take the recommendation as an implied directive to set previously unused generator undervoltage relay elements to the minimums stated in the Standard. That would cause more generator trips for system faults rather than fewer trips. Similarly, many generators that currently do not have undervoltage relay settings would trip at various other inherent voltage levels during a voltage excursion. With all of them set at or about 0.90 per unit, they would all trip at the same point, causing a catastrophic loss of generation. There are significant machine protection issues which are not addressed, such as the Volts/Hertz relay which protects the machine from an over-fluxing thermal hazard. Loss of generation consequential to problems on auxiliaries is a significant problem, which is not addressed in this Standard.
No
FERC 661-A is a wind generator facility ride-through performance criterion, not a synchronous generator relay setting requirement. They cannot be compared as being equivalent. A synchronous generator undervoltage capability will be quite different from an entire wind facility undervoltage ride-through capability. The 9 cycle zero voltage interval is inadequate. The 9 cycle setting would cover for most normally cleared faults but generators must also remain on line through faults with delayed clearing due to breaker failure as required in the NERC TPL Standards. The time interval for such clearing is more typically 12 to 15 cycles. This time delay can increase to 0.5 seconds if high speed protection is out of service, for example a single relay communication channel, at the time of a fault and the fault is then cleared in zone 2 time. SPCS believes that R.R.1 is worded in a confusing way. It implies that you had to trip in 9 cycles or less â€“ rather than not trip for a minimum of 9 cycles- albeit we want to wait longer than that. SPCS respectfully questions whether it is conceptually possible to properly state these criteria as a single curve. It is more appropriate to have separate requirements for wind generation and other generators. Additionally, they should differ related to points of interconnections (a contractual arrangement), and refer to the high-side of the GSU for all other generation. This would lend consistency and avoid unnecessary confusion. There are a number of important

issues that arise with current approach, including: ï‚§ In general, generator protection should not trip generators on UV, but should alarm, as stated in IEEE C37.102. Please also see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is more appropriate to call operator attention to a malfunction. ï‚§ The existence of a curve such as this in a NERC Standard will lead to generator owners enabling UV relays to trip and setting them per the curve, which is a serious danger to system reliability. ï‚§ For some specific situations such as unmanned hydro units, tripping on time-UV may be considered. ï‚§ The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate for other generators. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines. ï‚§ The Voltages presented are at the point of interconnection and are not directly translatable to machine relay voltage settings. ï‚§ Machine Volts/Hertz curves are a significant issue and are not addressed. ï‚§ The UV performance of plant auxiliaries is a significant issue, and is not addressed. ï‚§ The standard should be very clear to discourage plant owners from setting under- and over- voltage relays if they don't already have them, or need them for very specific situations. SPCS also is concerned because it appears the SDT has considered only the positive sequence voltage in developing the curves in Attachment 2. Overvoltage relays measure individual phase-to-ground or phase-to-phase quantities and SPCS expect that generator owners will apply these curves based on the quantities measured by the relays in developing relay settings. As such, the curves must be based on the quantities that are measured by protective relays and the quantities must be clearly stated. To highlight our concern, consider that for a line-to-ground fault at the point of interconnection on an effectively grounded system the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault. Under such conditions generators with overvoltage relays set per the curve may trip at 120% voltage prior to clearing the fault from the transmission system. Under these conditions tripping is not required for generator protection and may have a detrimental impact on system reliability, yet it is permissible per the proposed curve. There is guidance in the industry and C37.102 to provide dielectric (insulation) protection for extremely high voltages, however 120 % voltage is overprotecting the generator. For Generator protection, the first line of defense is generator surge arrestors but some units may also use a high set overvoltage protection as well. This voltage is a much higher level then 120% shown in the curve (i.e. 150% of rated voltage). Voltage relays applied to the system side of the generator step-up transformer should be configured and set in such a way that they do trip the generator for higher voltages on unfaulted phases for phase-to- ground faults. As you may know generator windings are sometimes tested with high potential: New machines can be tested as high as twice (200%) rated line-to-line voltage plus 1000 Volts (Commissioning High Pot) for one minute. Older Machines that are in service for significant time can be tested at 125% to 150% of rated line-to-line voltage (Maintenance High Pot) for one minute. There are some industry differences of opinion on this topic of course but 120% instantaneously is too low. Voltage settings are based on type of insulation material (Class F is in common present days) and its thickness. A curve would need to be developed that takes insulation thickness into account. USBR's practice is to use manufacture designed 105% continuous. Then, 59 is set a 110% of 105% (continuous use) for time coordination (TOV) and 130% of 105% of phase-to-ground voltage for instantaneous (IOV).
No
The interconnection Voltage is not relevant, only the amount of generation potentially lost to the system.
The FRCC UFLS has a requirement for generators to remain on line for 1 second with frequency down to 57.5 Hz. Regional differences are developing as the Regions perform studies to current UFLS strategies while considering the coordination requirements of generator underfrequency tripping. To date, NPCC and FRCC may be the only regions that have completed their studies. It is recommended that PRC- 024-1 wait on going forward in the standards process until the regions conclude their studies and develop their requirements based on their particular portions of the interconnected power system.
Yes
PRC-024 should only apply to non-synchronous machines. Coordination of synchronous generator voltage and frequency protective relay settings with transmission protection systems should be addressed along with all other coordination in PRC-001 â€“ Protection coordination. SPCS is preparing a Technical Reference paper on such coordination that is expected to be completed in June, 2009. Generator voltage and frequency protective relays are included in that that paper. The Attachment 2 voltage ride through curve was developed, to SPCSâ€™ understanding, by compiling a number of system events delineating those events whereby the tripping of generators would exacerbate the event. It does not appear that the SDT analyzed data from the August 14, 2003 Northeast Blackout. Actual data from the event in Michigan, before the system cascaded and broke apart revealed 345 kV system voltages of less than 0.9 per unit. Some

generators in Michigan tripped by undervoltage relays set at 0.9 per unit that significantly accelerated the cascade. Even those generators along the western fringe of the soon-to-be separated power system were of event more concern; data indicated these large units were experiencing 345-kV voltages of less than 0.9 per unit. Those generators did not trip because they did not have undervoltage relaying set to trip. Had these units tripped on undervoltage relaying, the event would have extended much further to the west of the actual impacted area. The Standard requires generator relays to be set based on a voltage at the interconnection point to the BES. However the relays are typically connected to a voltage source at the generator, not the BES interconnection. The translation from generator terminal voltage to a point of interconnection voltage is not a direct relationship. It will vary depending upon the assumption made for generator real and reactive output, or the distance to the â€œpoint of interconnection.â€ The Standard gives no direction regarding these assumptions. The voltage to be sensed must be the generator terminal voltage. IEEE C50.13 describes the standards to which the modern generators were built. This standard recommends reducing unit output after ascertaining the presence of an undervoltage alarm. This standard does not recommend unit tripping. Totally different relay settings will be obtained with different generator output assumptions. This lack of consistency will make it impossible to determine if compliance to the Standard is achieved. SPCS also have concerns with the overfrequency curve in Attachment 1 in light of the August 14, 2003 Northeast Cascade and Blackout. During the sequence of events an island formed consisting of portions of western New York and eastern Ontario with a significant generation-load mismatch. The surplus generation in the island resulted in an overfrequency condition to which several large generating units responded to arrest the overfrequency at 63 Hz. Had those units been set to trip on the proposed curve on August 14, the units would have tripped prematurely potentially leading to a collapse of the island. While the overfrequency curve may be acceptable as a floor for setting the overfrequency relays, there should also be a requirement to coordinate the overfrequency tripping with the unit controls and unit capability to maximize the ability of machines to control overfrequency while operating within their capability. Undervoltage alarms as experienced by hydro, fossil, combustion, and nuclear units are an indicator of possible thermal issues within the generator. Other alarms from RTDs and hydrogen pressure are better indicators. Manufacturers recommend operator action up to and including reduction in unit output rather than a unit trip. Tripping units on undervoltage is not recommended by the IEEE C37.102 standard on generator protection. Rather C37.102 also recommends alarm. Each type of unit, hydro, fossil, nuclear, combustion, and renewable generator have different thermal issues relating to system undervoltage. A single curve over-simplifies the issue to the point that system reliability is degraded. If any curve is included, it should be focused only on wind turbines as they have voltage ride through controls. Attachment 2 requires voltage evaluation at the system voltage level. Concerning Attachment 1, SPCS believes this is mainly present to insure that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." SPCS suggests that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs. The SDT has not described how the curve was compiled. Technical committees within the IEEE went to great lengths to describe the turbine blading off-frequency limitation curves. Every manufacturer submitted their curve and a family of curves was created that showed distinct curves for each manufacturer. The NERC 1978 document, "Underfrequency and Undervoltage Relay Applications Large Turbine Generators included a collection of individual manufacturer which when plotted together provided a prospective on the widely varying limits of the various turbines. There is a danger of misinterpretation to use one curve. In PRC-024-1 there was no description stating how the curve was developed. If a machine is not at risk and if a UFLS simulation shows that the bottom frequency will occur outside of the "one size fits all curve" then there should be a provision to use the manufacturer's curve rather than shed more load just to fit the attachment 1 curve. A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed â€¦ relaying not to trip during â€¦" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and Voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer. Concerning A.R1.2 and Attachment 1, the language refers to a â€œno trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. SPCS would suggest that setting directly on the curves should be permitted. For example, if 1.0 seconds at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 seconds at 57.79 Hz. SPCS suggests "Setting directly on the curves is permitted, and settings outside the curves are permitted." Concerning A.R2, this Standard addresses setting of Voltage relays based on Voltage

at the point of interconnection, which is not directly translatable to Voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard. Simply setting the generator protection relay at 0.90 per unit may, in fact, be an incorrect setting to achieve the desired performance. Settings must include allowances for all equipment tolerances: voltage transformer errors, relay tolerances, and testing instrumentation errors. The actual setting needed to account for such variances may require that the relay be actually set to trip at 0.84 or 0.86, or some other seemingly conflicting value, in order to achieve the goal of not tripping at 0.90 per unit.
Group
PJM Interconnection
Patrick Brown
PJM Interconnection
Yes
Yes
Yes
Yes
Yes I agree with the approach
Yes
Yes
In R2.2.1, replace -greater- with -faster- or -slower-, whichever is correct. In R2.2.3 replace -intended- with -required-. In R4, replace -written- with -documented-. In R5, add an -s- to -System- in the parentheses. In R3, R4 and R5 - Concerned with the GO responsibility to send to their RC, PC, TO and TP. Would rather see the GO responsibility be to just to respond to any RC, PC, TO and TP requests.
Individual
Brent Ingebrigtson
E.ON U.S.
Yes
Yes
No
Yes
No
E.ON U.S. believes that the standard should apply to facilities at 200 kV and above in order to be consistent with equipment thresholds of other NERC standards.
Yes I agree with the approach
Yes
No
Group
Dominion

Jalal Babik

Dominion Resources Services, Inc.

Yes

Yes

Yes

Yes

No I disagree with the approach

All generators identified in a transmission owner's restoration plan warrant a high VRF. Additionally, generators â‰¥ 500 MVA warrant a high, generators > 100 MVA but < 500 MVA warrant a medium and generators â‰¤ 100 MVA warranty a low VRF

Yes

We are not aware of any. However, we are aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service. We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicted upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service.

Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.

Yes

We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that " For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected " We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system under voltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator? (2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations? If the standard is intended to apply to volts per hertz relays, suggest: 1. Revising footnote 1 to specifically include volts per hertz relays. 2. Revise Steps 4.2.1 and 4.2.2 to specifically include volts per hertz relays. 3. That the standard should incorporate specific guidance for facilities using volts per hertz logics and include a graph showing the voltage and frequency excursions in terms of volts per hertz.

Group

Northeast Power Coordinating Council

Guy Zito

Northeast Power Coordinating Council

No

Both bullets should be checked above (form will not accept). The responses received were divided, and below are the comments received for your consideration. The Generator Operators, and not the Generator Owners, are typically responsible for establishing relay setpoints, calibrations, and maintenance. The Generator Owner is the Functional Model entity that has direct control over the generating unit protection settings.

No

Both bullets should be checked above (form will not accept). The proposed standard addresses all issues identified in the Standard Authorization Request. Coordination of generator and transmission system protection is addressed in PRC-001. As presently constituted this Standard will likey result in the inappropriate enabling and setting of frequency and voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to its stated

purpose. This is supported in the comments provided below. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Yes
A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
No
Both bullets should be checked above (form will not accept). The curves should be revised based on generator capabilities and design requirements rather than the expected system response for simulated disturbances. Although the simulation results and tools used to develop the curves have not been provided it appears that the proposed curves are based on transient stability simulations. The transient stability program includes only the positive sequence component of system voltage and neglects phenomena that do not result in significant shaft torques. By contrast, protective relays measure individual phase or phase-to-phase quantities or in some cases specific sequence quantities. As proposed the curves may be interpreted differently in relay applications to the detriment of bulk electric system reliability and customer service. Since the curves will be used to set protective relays they should be based on the quantities that are measured by protective relays and the quantities should be clearly stated. We have provided examples of how the curves could be misinterpreted or misapplied if the curves are not constructed in terms of measured relay quantities and settings specific to the point of measurement: â€¢ Based on the proposed curve an overvoltage relay can be set at 120% with no intentional time delay. If this relay measures phase-to-ground voltage at the Point of Interconnection (POI) then for a close-in line-to-ground fault the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault (effectively grounded system), resulting in undesired generator tripping prior to clearing the fault from the transmission system. â€¢ Protection against overvoltages that are shorter in duration than the operating time of circuit breaker is provided by surge arresters on the high-voltage terminals of the transformer and by surge protectors on the terminals of the generator. The curve implies that for a voltage of more than 120% that the generator can trip instantaneously (without intentional time delay). We suggest that instantaneous trips at any voltage level are neither required nor effective for generator protection. The overvoltage curve should approach zero time asymptotically or alternatively 250% for 20ms, 135% for 300ms, 120% for 20 seconds, 110% continuously. Alternatively the curve should be based on generator capability rather than FERC 661A which is applicable to wind generators with very limited capability. â€¢ In the undervoltage region the 9 cycle zero voltage has been carried over from FERC 661-A which is to facilitate wind integration. The 9 cycle zero voltage ride-thru, although less than prior utility designs, may be sufficient. We again recommend that SDT translate the intended positive sequence values to phase quantities measured by the relay to avoid misapplication. A single-line-to-ground fault will result in a positive sequence voltage of approximately 0.5-0.7pu but the voltages on individual phases or between phases may be quite different. The curve appears adequate from a positive sequence perspective but may not be interpreted as intended. â€¢ In the undervoltage region we recommend that 85% be applied from 3 seconds to 15 seconds to ensure that generators stay connected longer than load and to permit time for automatic reactive element switching. There is no reason to trip this fast in this region Based on the proposed curves we are concerned that the SDT has considered only the system response to typical design contingencies and only the positive sequence voltage from transient stability simulations. Although we have suggested alternate values the final values will depend on how the curve is defined, the form of measurement and relay application. As proposed we believe the curves leave too much for misinterpretation and misapplication. We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following: > In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a malfunction. > The existence of a curve such as this in a NERC Standard will lead to generators enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability. > For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate. > The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines. > The minimum voltage for 9 cycles does not allow enough time to allow for breaker failure protection operation. 13 -15 cycles would be appropriate. > The voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings. > Machine Volts per Hertz curves are a significant issue and are not addressed. > The UV performance of plant auxiliaries is a significant issue, and is not addressed. > We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to

this Standard.
No
Both bullets should bec checked above (form will not accept). Reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage. We are concerned that the generator unit capacity thresholds are set too high. Given the tolerances in UFLS program design, the unit capacity thresholds should be established to ensure that 99 percent of the generation in a system complies with the requirements of this standard. The SDT should identify unit capacity thresholds on this basis, similar to how thresholds were developed in MOD-026. The interconnection voltage is not relevant, only the amount of generation potentially lost to the system. Some sub-regions, employing a UFLS Program, are dependent on Generator Owners/Operators meeting the specifications for generator Underfrequency setpoints in order to maintain a viable UFLS Program. For sub-regions where a large percentage of the total generation fleet is comprised of individual units < 20 MVA and connected to buses < 100 kV, the contribution of these units to the overall success of the sub-regions UFLS Program are more pronounced. It is suggested that the threshold should be established by refering to the requirements of the Region or as established by the Reliability Coordinator (sub-region). As an alternative, it is suggested that all generating units operating in a Reliability Coordinators' or RTO/ISO's market system, regardless of size, shall follow this Standard based on their materiality to the reliability of the bulk power system.
No I disagree with the approach
Both bullets should be checked above (form will not accept).
No
Both bullets should be checked above (form will not accept). Given the potential impact on survivability of an island, and the need to lower the unit capacity thresholds for which this standard is applicable, as recommended in the comment to Question 5, it is suggested that the folowing Violation Risk Factor thresholds be applied: High > 100 MVA Medium > 20 MVA and < 100 MVA Lower < 20 MVA Given the potential impact on survivability of an island, and the recommendation in our response to Question 5 to lower the unit capacity thresholds for which this standard is applicable, we recommend the following Violation Risk Factor thresholds: High >100 MVA Medium > 20 MVA and â‰¤ 100 MVA Lower â‰¤ 20 MVA
We are aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service. We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicated upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service. The Quebec Interconnection, within the Eastern Interconnection, would need different settings from the ones listed in Attachment 1 to coordinate with its UFLS program.
Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.
Yes
Referencing R5 and R6 of the Standard: The Reliability Coordinator should be give veto power over exceptions to the requirements herein. Should the Generator Owner/Operator not be able to, or be unwilling to, make changes to setpoints to come into compliance with this Standard, the Reliability Coordinator should be given the authority to invoke required mitigation, such as requiring the Generator Owner/Operator to contract for compensatory load shedding up to the total amount of MW of each generating unit that fails to comply with the required setpoints. In addition, The "Off-Nominal Frequency Capability Curve" in Attachment 1 does not coordinate with the underfrequency load shedding (UFLS) program design parameters proposed by the NERC Underfrequency Load Shedding Standard Drafting Team for Project 2007-01. The misccoordination occurs in the time range approximatley between 5 and 10 seconds. This miscoordination can be eliminated by extending the horizontal line at 57.8 Hz to 5 seconds and revising the diagonal line to have endpoints at 57.8 Hz/5s and 59.5 Hz/1800s. This modification will provide coordination with the UFLS program design parameters while still maintaining coordination with turbine-generator capability. Due to the time scale on the graph in Attachment 2, the curves do not indicate the time at which the transient overvoltage and undervoltage requirements end, at which point the continuous voltage requirements would be applicable. Here are several other points that have come up regarding other parts of PRC-024-1 that were not

covered above: > Concerning Attachment 1, we believe this is mainly present to infer that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled. > A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed â€¦ relaying not to trip during â€¦" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer. > Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted." > Concerning A.R2, this Standard addresses setting of voltage relays based on voltage at the point of interconnection, which is not directly translatable to voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard. We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that " For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected " We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system undervoltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator? (2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations?
Individual
Brendan Kirby
AWEA
Yes
Yes
PRC-024 should be a performance standard but since that is unlikely to pass I can live with a relay setting standard
No
Yes
Yes
Yes I agree with the approach
Yes
No
Individual
Mark L Bennett
Gainesville Regional Utilities
No

In a number of smaller utilities, they are the same and do not need to be addressed separately
No
In some areas there is no reason to include generators less than 100 MVA
No
No
I am concerned that Generator Operators even understand what is written above
Yes
Yes I agree with the approach
No
I believe that > than 100 mva should only be included
Individual
Michael Goggin
American Wind Energy Association
Yes
Yes
A relay setting standard is fine, although the wind industry would also be able to comply with the standard if it were a performance standard.
No
Yes
Yes
Yes I agree with the approach
Yes
No
Individual
Cleyton Tewksbury
Veolia Environmental Services
No
The generator operator is the entity charged with maintaining the facility. Therefore, the GOP has all the necessary records and procedures.
Yes
No
Yes
No
Additional criteria would be useful to identify units that are critical to the BES. If a BA and/or TOP has identified a unit a non-critical, then such a unit should be exempt from this standard regardless of size and connection voltage.
No I disagree with the approach

The delineation should be based on actual or potential impact to the BES of a unit tripping as determined by the BA and TOP modeling.
No
Size should not be a factor, only practical impact to the BES.
No
Individual
test
test
Yes
No
fgsfgdfg
No
ddfsd
fsdfsdf
Yes
dfsdf
No
dfsdfdsf
No I disagree with the approach
sdfsdfsd
Yes
dfsdfsdf
dsfsfsdf
dsfsdfsdf
Individual
Mark Ringhasuen
Old Dominion Electric Cooperative
No
I agree that the Go is the primary function for this requirement, but given the multitude of Go/GOP configuations out there, I think the GOP function should also be included in the applicability secttion of this standard.
Yes
No
I am not 100% sure this is the case, but I am fairly confident all our units do meet these thresholds.
Yes
In general, I agree with your curve. I need to review more completely before I am ready to vote Yes on it.
Yes
This is the NERC/FREC set levels, all units with this scope should have to comply with the standard. Units that are not within the above criteria should be exempt from it as they are not aware, possible to provide their input.
No I disagree with the approach
I assume this was because the bigger units have a bigger impact on reliability than the smaller units. I am fine with this approach, but might have a minor comment on the break levels.
Yes
Might have a minor tweak in the future.
No.
No.
Yes
Provide some insight on Technical Exceptions for generators that cannot met these requirements

(the CIP TFE process might be useful in this)
Individual
Patrick Farrell
Southern California Edison Company
No
The Generator Operator should be the functional entity to whom the standard applies because Generator Operators tend to change the settings without warning or permission.
Yes
Yes
Uncertain, as curves and tables in attachments need additional clarification.
Uncertain, as curves and tables in attachments need additional clarification.
No
Additional information is need for clarity on the curve and table in the attachment.
Yes
Yes I agree with the approach
Yes
Yes
The curves and tables in the attachments require additional clarification.
Individual
Barry Francis
Basin Electric Power Cooperative
Yes
I have some problems with the intent of this standard in general, but a standard of this nature would have to apply to the generator owner.
No
Generation under frequency protection is an area I have spend much time on over the last 20 years, and I admit that I hold some strong opinions, but these opinions were arrived at after much study, disturbance analysis, and from being directly involved in actual design of three regional underfrequency load shedding (UFLS) programs. It appears that the generator off-nominal frequency protection limits shown in attachment 1 represent someone's judgment call of what is a reasonable loss of life per event, what the expected minimum frequency might be when load shedding occurs, and so forth. Such judgment calls are subjective, and there is room for interpretation. I feel that generation underfrequency/overfrequency settings of this nature have to be developed on a regional basis as part of a regional underfrequency load shedding program. I am uncomfortable with this showing up in a draft NERC standard without any supporting technical documentation or justification. I agree that unit capabilities have to be considered, but perhaps more important, we have to consider the realities of what we can achieve with UFLS and give ourselves enough generator tripping delay time and relay margin to make the program work. Tradeoff's are involved, and this type of underfrequency analysis is inherently an estimation, so some time delay margin is needed to ensure coordination with load shedding. If generation trips too soon, the island imbalance will increase and it may not be possible to prevent total collapse of the island. Keep in mind that the real off-nominal frequency loss of life exposure is when black start programs try to pick up the pieces after load shedding fails, and premature tripping of generation is what causes load shedding to fail. In addition, hydro systems can operate at much lower frequencies than steam units, and this criteria is not appropriate for hydro systems. In my opinion, UFLS is supposed to be a safety net to cover the unforeseen, and it needs to be designed with that in mind. Ideally, we want it to be as robust as possible. Relay coordination is going to be more robust when based on worst-case performance and not on best case. This helps deal with real world complications imposed by things we have not anticipated or foreseen, or due to "as implemented" programs always being a little different than the ideal stated in the design phase. My most recent involvement with UFLS and generator off-nominal frequency protection coordination came about through the MRO Underfrequency Load Shedding Task Force effort that developed a new coordinated UFLS program for the MRO footprint. I served as chair of this taskforce and did much of the analysis. I do not want PRC-024-1 to establish standards that conflict with the MRO program. Doing so would sacrifice the effectiveness of the load shedding program we came up with. There are a couple of other areas where conflicts occur. This is in regards to how to deal with programs that need to shed more

than the minimum amount of load, and in regards to the overfrequency implications. I will discuss the issues in sequence. Although the MRO UFLS Taskforce expects that under "typical conditions" that minimum frequency will be above 58 Hz, (for loss of generation/import of up to 30% of system load in the island), our worst case simulations indicate we could briefly dip below that, and we used our worst case results to set generation protection times and delays. In addition, our "equivalent inertia" modeling approach ignores machine to machine oscillations which might cause frequency at different locations to differ by .2 Hz or so as the system rings down. For this reason, we chose 57.6 Hz as the point where instant tripping is allowed. This is below our worst-case minimum frequency of 57.77 Hz (for a very low inertia, low damping, no governor scenario that is perhaps overly pessimistic). This can also be justified by considering that our design criteria set a target of average system frequency >= 58 Hz, which has to be adjusted by about - .2 Hz for machine to machine oscillations seen in the real system and not in our model, plus about .2 Hz margin to ensure good relay coordination). In order to come up with the MRO generation protection settings we monitored time spent in frequency bands spaced .1 Hz apart and we consider the performance over the full range of coverage (0 to 30 % loss of generation) and considered a wide range of assumptions concerning system based inertia (H system base = MW-sec stored in rotating mass divided by P gen) and damping in addition to a possible range of governor actions. We optimized the program to minimize time spent below 60 Hz while addressing all the other constraints we had to deal with. Once we knew the expected worst case times in each .1 Hz band below 60 Hz for the optimized program, we came up with the stair step type of generation time delay settings that gave a reasonable fit to the expected worst-case time versus frequency information (plus some margin) with the fewest frequency bands. The MRO UFLS effort tried to anticipate as much complication as possible, but we could not cover all of the inherent uncertainty involved. No one could. The main source of uncertainty we could not deal with is how potential overvoltageâ€™s may increase load and decrease the effectiveness of the load shedding program. This gave us additional justification for using a "no net governor response" scenario for evaluating coordination between load shedding and generator protection (this voltage uncertainty is not the only reason for using a no governor assumption: basically units that are base loaded cannot respond to underfrequency, power/load controllers may override governor action, combustion turbine thermal limits will quickly override their governor action with power dropping off faster than the frequency decline, wind generation may drop off and would not have a governor anyway, and so forth; the bottom line is that we do not know what level of net governor type of action we can count on, and what little we get may be offset by increases in voltage). To fully understand what we did you will have to refer to the MRO UFLS report on the MRO website. The short version is that we ran 1000's of cases to arrive at our conclusions. What we came up with for generator underfrequency protection minimum time delays is what we need to ensure the load shedding has time to play out to restore frequency and to give some margin to ensure relay coordination. If we tighten up the generation protection time delays and raise the frequency setting for the instant trip point, then there is a narrower range of conditions for which the UFLS program would be expected to work as intended. Our safety net becomes less robust, we make things less secure. On the other hand, the MRO load shedding program is designed to be the first line of protection for the generators as it is designed to force frequency recovery even in the absence of governor action by having small blocks of load shed on delay to kick us back towards 60 Hz when recovery is too slow. Although there is a chance that frequency may be slow to recover as a worst case, most of the time it will recover much faster than the times we used for generation tripping coordination. The expected time spent below 60 Hz sort of takes on the form of a probability density function. This type of information gives a better idea of what units may be exposed to. Therefore, our approach was to coordinate generation off-nominal frequency protection to match the worst case, and then do everything possible to minimize underfrequency exposure to generators when designing the load shedding program. The recommendations of the MRO UFLS report should take precedence over what is being proposed in this document. In MRO, we recognize that the Canadian portion of MRO needs to shed more than 30% of connected load. The MRO UFLS report indicates that any program that needs to shed more than 30% of load will need to relax the MRO generator off nominal frequency time delay settings for generation and accept longer delays and lower minimum frequencies. This is an engineering reality. The Off-Nominal Frequency Capability Curve on Attachment 1 does not give this kind of flexibility. Alternately, some improvement on minimum frequency can be realized by designing a program that oversheds but then the program will be prone to overspeed problems. Programs can also start shedding at higher frequencies to improve the minimum frequency but then that creates other coordination problems with neighboring programs. This standard writing process should not replace engineering judgment. Utilities need flexibility so they can make the necessary compromises after all things are considered. Making adjustments to generation protection is most likely the best approach to ensure coordination with these larger load shedding programs. The diagram from PRC-024-1 may suggest to some folks that over frequency tripping is going to be needed or perhaps even encouraged. I do not know what the intent is, so I will just express my concerns up front. I have serious reservations about applying dedicated relays, of the type used for underfrequency protection, to trip units on overspeed. Extreme caution is needed. That is a good way to ensure total collapse of a power grid. Seriously, this could be catastrophic. Consider that plants already have internal overspeed controls. These are needed to deal with full load rejection. These controls are in addition to the normal governor, and are much more drastic. These emergency overspeed controls are not modeled in stability cases, but they exist, and will take drastic action to slow down units if frequency gets high so I feel confident that the units self protect and take care of themselves. I believe that overspeed protection should be left to these inherent controls, and that we should not put in additional relays to trip generation on overspeed unless this is done carefully and solely for the purpose of restoring load and generation within an island. Plant internal overspeed controls have to limit speed following full load rejection, but they will also react to partial load rejections that we get by islanding. If a plant loses all lines to it (i.e. full load rejection), then go ahead and allow these inherent controls to trip the unit on overspeed or do what ever is needed. NERC does not need a standard for that. The emergency overspeed controls that protect for full load rejection can also activate on an islanding condition where we have too much generation in an island. On steam units these controls kick in between 61 to 62 Hz (it varies with each unit so I have to generalize), so system frequency is unlikely to get much higher than 61.4 Hz to 62 Hz (most that I have seen activate around 61.2 to 61.4 Hz) no matter how large the initial imbalance. Once these controls activate frequency is no longer a measure of the imbalance between load and generation. The action taken to prevent overspeed involves things like closing all the steam valves on thermal units, so it is safe to say we cannot stay in this high frequency condition for too long before random unit trips start to occur due to any number of internal plant problems. Often times one plant dies first and rebalances things for other units. The random nature of what happens next complicates any planned unit tripping actions to correct the imbalance. If dedicated unit tripping on overspeed is to be done, it can only be done on a few selected units and only as a way to hammer the imbalance back to a smaller size that we can deal with. The worst of all worlds would be to apply overspeed tripping to all units like we do for underfrequency. That would ensure any island with an initial excess of generation is going to go black after we dump all the generation. If generation is tripped to correct overspeed in an island, it has to be done in small increments (about 1 to 1.5 % of remaining load) and trip times have to be staggered. This is something that has to be studied on a case-by-case basis. In summary, we do not believe that it is appropriate to be creating a standard like this to specify settings for underfrequency/overfrequency protection for all generation. The technical basis of these limits are not given, and these setting may not coordinate with existing or proposed underfrequency load shedding programs. Aggressive load shedding programs are quite likely to need to accept more time below 60 Hz to coordinate with underfrequency relaying and expected system frequency recovery times. Protection settings of this nature should be developed in conjunction with underfrequency load shedding programs so that appropriate trade offs can be considered. Such coordination is most effective at the regional or subregional basis where a specific load shedding program can be evaluated in detail. We must give sufficient time for load shedding to act even if it means we need to accept some additional potential loss of life to generation for some hypothetical underfrequency event.

No

It is unclear what limits apply to wind generation, but we believe our conventional generation can easily accommodate the settings defined by Attachment 1, even though we feel that such off-nominal protection settings should not be established in this standard and that such coordination should occur at the regional level were UFLS program details are worked out. I would like to offer some observations based on real life experience. Our experience is that some folks have a good technical understanding of generation capabilities and others do not. In many instances, folks do not know what actual capabilities are, and if the proposed settings conflict with existing settings then they will initially report that they cannot accommodate the recommendations (the status quo carries a lot of weight even when no one can find the original justification for existing settings). Generally, all the parties have to get together and work through things to create a higher level of awareness of the issues so we can eliminate misconceptions. The new non-utility generation owners do not have the same load serving obligations as traditional utilities and this gives them different incentives for how they want to set generation protection. In many instances, they want to trip too early, to the detriment of the grid.

No

This may be appropriate but I have not seen the supporting technical report so I cannot say that I agree.

No

This is likely to be something that has to be applied on a case by case basis, with consideration given to how many units we have that would not be covered by some sort of coordinated UFLS/generation protection settings. There is some latitude to make exceptions, but in the future, we may have many more units that fit this category, and then this becomes a big issue. Units which trip too soon will just impact the load shedding program unless a corresponding amount of load is shed at essentially the same time and more or less at that same location.

No I disagree with the approach

This may be appropriate but I have not seen the supporting technical report so I cannot say that

I agree. This is likely to be something that has to be applied on a case-by-case basis, with consideration given to how many units would be excluded in some geographic area. There is some latitude to make exceptions, but in the future, we may have many more units that fit this category, and then this exclusion becomes a big issue.
No
see above comment
See the detailed answer provided to question 2. It covers the need for regional variance.
The proposed generation off-nominal frequency criteria conflicts with the MRO UFLS program, and will not work for programs that need to shed more than 30% of system load. Technically this is not a conflict with regulatory functions, rule order, tariff, rate schedule, legislative requirement or agreement; but it is a conflict with our efforts to design an appropriate load shedding program for the MRO region.
Individual
Tony Kroskey
Brazos Electric Power Cooperative
Yes
Yes
Yes
Yes I agree with the approach
Group
Constellation Power Generation & Constellation Nuclear
Scott Etnoyer
Constellation Power Generation
No
The Generator Operators, and not the Generator Owners, are typically responsible for establishing relay setpoints, calibrations, and maintenance. The Generator Owner is the Functional Model entity that has direct control over the generating unit protection settings.
No
The proposed standard addresses all issues identified in the Standard Authorization Request. Coordination of generator and transmission system protection is addressed in PRC-001. As presently constituted this Standard will likey result in the inappropriate enabling and setting of frequency and voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to its stated purpose. This is supported in the comments provided below. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Yes
A number of our units do not meet this requirement but it is not known which of these cases are, due to actual machine design limitations.
No
The curves should be revised based on generator capabilities and design requirements rather than the expected system response for simulated disturbances. Although the simulation results and tools used to develop the curves have not been provided it appears that the proposed curves are based on transient stability simulations. The transient stability program includes only the positive sequence component of system voltage and neglects phenomena that do not result in significant shaft torques. By contrast, protective relays measure individual phase or phase-to-phase quantities or in some cases specific sequence quantities. As proposed the curves may be

interpreted differently in relay applications to the detriment of bulk electric system reliability and customer service. Since the curves will be used to set protective relays they should be based on the quantities that are measured by protective relays and the quantities should be clearly stated. We have provided examples of how the curves could be misinterpreted or misapplied if the curves are not constructed in terms of measured relay quantities and settings specific to the point of measurement: â€¢ Based on the proposed curve an overvoltage relay can be set at 120% with no intentional time delay. If this relay measures phase-to-ground voltage at the Point of Interconnection (POI) then for a close-in line-to-ground fault the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault (effectively grounded system), resulting in undesired generator tripping prior to clearing the fault from the transmission system. â€¢ Protection against overvoltages that are shorter in duration than the operating time of circuit breaker is provided by surge arresters on the high-voltage terminals of the transformer and by surge protectors on the terminals of the generator. The curve implies that for a voltage of more than 120% that the generator can trip instantaneously (without intentional time delay). We suggest that instantaneous trips at any voltage level are neither required nor effective for generator protection. The overvoltage curve should approach zero time asymptotically or alternatively 250% for 20ms, 135% for 300ms, 120% for 20 seconds, 110% continuously. Alternatively the curve should be based on generator capability rather than FERC 661A which is applicable to wind generators with very limited capability. â€¢ In the undervoltage region the 9 cycle zero voltage has been carried over from FERC 661-A which is to facilitate wind integration. The 9 cycle zero voltage ride-thru, although less than prior utility designs, may be sufficient. We again recommend that SDT translate the intended positive sequence values to phase quantities measured by the relay to avoid misapplication. A single-line-to-ground fault will result in a positive sequence voltage of approximately 0.5-0.7pu but the voltages on individual phases or between phases may be quite different. The curve appears adequate from a positive sequence perspective but may not be interpreted as intended. â€¢ In the undervoltage region we recommend that 85% be applied from 3 seconds to 15 seconds to ensure that generators stay connected longer than load and to permit time for automatic reactive element switching. There is no reason to trip this fast in this region Based on the proposed curves we are concerned that the SDT has considered only the system response to typical design contingencies and only the positive sequence voltage from transient stability simulations. Although we have suggested alternate values the final values will depend on how the curve is defined, the form of measurement and relay application. As proposed we believe the curves leave too much for misinterpretation and misapplication. We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following: * In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a malfunction. * The existence of a curve such as this in a NERC Standard will lead to generators enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability. * For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate. * The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines. * The minimum voltage for 9 cycles does not allow enough time to allow for breaker failure protection operation. 13 -15 cycles would be appropriate. * The voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings. * Machine Volts per Hertz curves are a significant issue and are not addressed. * The UV performance of plant auxiliaries is a significant issue, and is not addressed. * We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard.

No

Reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage. We are concerned that the generator unit capacity thresholds are set too high. Given the tolerances in UFLS program design, the unit capacity thresholds should be established to ensure that 99 percent of the generation in a system complies with the requirements of this standard. The SDT should identify unit capacity thresholds on this basis, similar to how thresholds were developed in MOD-026.

No I disagree with the approach

No

We are not aware of any. However, we are aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service.

We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicted upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service.
Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.
Yes
The 4 kV protection that includes underfrequency and under volthge relays trip the generator in some of our plants. The SDT needs to clarify whether this standard applies to such protection.
Individual
Harianto Suryo
Lakeland Electric
Yes
Yes
No
Yes
Yes
Yes I agree with the approach
The VRF levels should range from low to high based on unit size and how the unit size impacts BES.
Yes
No
No
No
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
Yes
No
Yes
Yes
Yes I agree with the approach
Yes
none
none
No
Individual
D. Bryan Guy

Progress Energy, Inc.
Yes
Since the generator operator does not own the equipment addressed by the standard, he cannot change the settings without the owner's approval. The standard potentially requires changing the frequency and voltage relay trip settings. Since the generator owner owns the equipment, they also own the settings and should be the one held accountable for meeting the requirements of this standard.
No
The purpose of the standard, to ensure that generators ride through the proposed system transients, will not be accomplished by only looking at generator protective relays. PE is concerend that these same profiles for frequency and voltage (Attachment 1 and 2) could later become applicable to all plant equipment. The generating plants are not designed to ride thru/stay connected for these proposed profiles.
Yes
100% of Progress Energy nuclear units will not stay connected per the proposed Attachment 1 and 2 due to auxliary equipment protection. 70-80% of the combustion turbine units would trip during the frequency excursions proposed by NERC. To make sure that generation "ride through" is coordinated with conditions that could damage all types of generation facilities, Progress Energy recommends that the SDT consult with turbine manfacturers to develop the frequency profile. Frequency limitations are typically driven by turbine manfacture design. We also need to the mindful of the total cummulative off-frquency excursions limits laid down by the turbine manufacturers. For example, most large steam turbine vendors prohibit turbine operation below 58 hz in order to prevent the probable occurrence of turbine blade resonance (turbine blade failure). Our nuclear plant operators will immediately manually trip the turbines at 58 hz to prevent equipment damage. For combustion turbines under frequency limitations exist below 59 Hz while the maximum operating duration at 59.5 Hz is limited to 60 seconds. Of our five nuclear plants, all five would not be capable of riding through either the proposed frequency or voltage transitents due to manual turbine and automatic reactor protection settings. These settings are not generator protective relays but they will result in a complete loss of generation. Two Progress Energy nuclear plants will trip on reactor coolant pump undervoltage below 80% pu at 0.75 seconds and one will trip on underfrequency below 58.2 hz at 0.2 seconds.
Approximately 3,500 MW of nuclear generation for SERC and 900 MW for FRCC. Approximately 3500 MW CT generation in SERC and 5000 MW CT generation in FRCC.
No
PE is concerend that the proposed profile for voltage (Attachment 2) could later become applicable to all plant equipment. The generating plants are not designed to ride thru/stay connected for this proposed profile. 100% of our nuclear units will trip if subjected to the proposed voltage transient test. The trips would be due to reactor coolant pump undervoltage, reactor coolant pump power monitoring protection, and reactor protection system power supply undervoltage exceeding their respective time delays during the voltage excursion. Each nuclear plant has slightly different trips based on the reactor design and vintage.
Yes
All generator units with the given thresholds are registered in the NERC compliance registry. We consider that such units should adhere to the requirements in the standard. Each system reacts differently to the loss of different sizes of generators. This standard, which is applicable to every entity, should cover all such situations. Hence, the given thresholds, though restrictive, are adequate.
No I disagree with the approach
It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH. Consider the example where a plant consists of numerous medium (100-200 MVA) units with a common relay setting error. WECC have relatively small units, but potentially large impact when the whole plant is affected.
No
There should not be levels.
No. FRCC has suspended work on a regional version of PRC-024. The regional version will have to reviewed and compared to the NERC standard once developed.
Yes, if the standard is extended to other plant equipment NRC nuclear plant licenses will be in conflict.
Yes
1. Recommend deleting proposed R2.2.2. If not deleted the language needs to be clarified as follows: "meet a shorter voltage ride through" should be changed to "meet a less stringent voltage ride through". 2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field. 3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request" 4. The purpose and the applicability of the standard needs to be

revised to clearly specify that the scope of PRC-024-1 only applies to main generator protective relaying and excludes protective functions associated with plant auxilary equipment.
Group
SERC Dynamics Review Subcommittee (DRS)
Rick Foster
Ameren Services
Yes
Since the generator operator does not own the equipment addressed by the standard, he cannot change the settings without the generator owner's approval. The standard potentially requires changing the frequency and voltage relay trip settings. Since the generator owner owns the equipment, they also own the settings and should be the one held accountable for meeting the requirements of this standard.
No
Settings for generator backup impedance and voltage restrained overcurrent relays need to be covered too. Their inclusion will provide complete coverage of the generator. There have been instances where these relays have operated in the past. We understand that this will drive the need for dynamic simluations because steady state simulations will not suffice.
Yes
However, the wording used in section R2.2.1 is confusing. The words should be changed to "For three-phase transmission system zone 1 faults with Normal Clearing, generator relaying shall be set longer than the expected fault clearing time, but not greater than nine cycles."
Yes
All generating units with the given thresholds are registered in the NERC compliance registry. We believe that these units should adhere to the requirements in the Standard. Each system reacts differently to the loss of different sizes of generators. This Standard, which is applicable to every registered entity, should cover these situations. Hence, the given thresholds, though restrictive, are adequate.
No I disagree with the approach
It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH. Consider the example where a plant consists of numerous medium sized (100-200 MVA) units with a common relay setting error. Even though the individual units are relatively small, there is a potentially large impact when the whole plant is considered.
No
There should not be levels
Yes
1. We recommend deleting the proposed section R2.2.2. If not deleted, change: "meet a shorter voltage ride through" to "meet a less stringent voltage ride through". 2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field. 3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request"
Individual
Bob Shanks
NIPSCo
Yes
Yes
Yes
4.7 % estimated percentage of units that can't meet thresholds due to design limitations:
155 Estimated total MW capacity of units that cannot meet the requirement.
Yes
Yes I agree with the approach
Yes

Yes
R4 These groups should already have this information. The coordinators or planners should have proof and be able to provide this information now. R5 Normally would not accumulate enough time in the under-frequency zone to be a danger to the turbine blades but under unusual circumstances might accumulate too much time and not be able to continue to operate in the under-frequency region that is being specified. We might not have enough time to wait for the 30 day period.
Group
Luminant Power
Rick Terrill
Generation Compliance
Yes
Yes
No
Yes
Yes
Yes I agree with the approach
Yes
NA
NA
No
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
Yes
A performance standard would be virtually impossible to perform and verify for all the equipment at a plant. The relay approach may not meet the SAR objective for generators to remain on line through voltage and frequency excursions, but this approach is the only practical way that allows standard requirements to be written and enforced.
Yes
A single unit not meeting these thresholds (an unregistered unit) can always be registered if a technical justification is given and proven. However, this does not mean a "blanket" registration can apply to all units (unregistered units) that do not meet these thresholds.
Yes I agree with the approach
Individual
Rick White
Northeast Utilities
Yes

Yes
Information not available at this time.
Information not available at this time.
Yes
No
Significant generator capacity may be connected at distribution voltages and set with sensitive anti-islanding frequency/voltage setpoints. These generators need to report their setpoint data to the owner of any UFLS/UVLS systems that may be affected by the generator performance. This can be a significant amount of generation relative to the size of the UFLS/UVLS program. Consideration should also be given as to whether the requirements should apply to generators where the site aggregate is >20MVA.
Yes I agree with the approach
Yes
R2.2.1 seems to imply that a generator must set an undervoltage trip with a time delay of no more than 9 cycles. This seems to conflict with the intent of PRC-024. Is the intent perhaps to require the TO to clear Zone 1 faults in no more than 9 cycles? Or is the intent to allow the GO to set the time delay as low as 9 cycles and no less? I suggest the latter. R3, R4, and R5 - This information should be provided to the owner of any UFLS or UVLS as well.
Group
Southern Company
Hugh Francis
Southern Company Services
Yes
If the standard is in place, it belongs to the Generator Owner. The SAR seemed to be written for transmission, but this standard seems to be evolving to a geneator setting standard. Does the SAR need to be revised? Although GO has the access to the equipment settings/records, GOP may not, GOP is the entity to operate the units. GO must communicate settings to the GOP. Since the generator operator does not own the equipment addressed by the standard, he cannot change the settings without the generator owner's approval. The standard potentially requires changing the frequency and voltage relay trip settings. Since the generator owner owns the equipment, they also own the settings and should be the one held accountable for meeting the requirements of this standard.
No
What the standard addresses is probably what is practical, but the ultimate goal of the SAR is not practical to implement. We question whether the goal of this standard can be truly addressed from a practical standpoint. The scope of the protective equipment covered in the current draft excludes excitation system protection including over excitation, station service under voltage protection, certain nuclear facility protection schemes, boiler controls, turbine controls, each of which may not ride through the frequency and voltage swings. We feel as though the limited approach of specifying F and V relay settings on the generator may be futile in improving the ability to ride through â€“ yet on the other hand the inclusion of all of the impacted plant subsystem components would be practically and financially unmanageable. In other words, will any appreciable improvement in system reliability result from the implementation of this standard looking at F and V gen settings only. Settings for generator backup impedance and voltage restrained overcurrent relays may need to be covered too. Their inclusion will provide complete coverage of the generator. There have been instances where these relays have operated in the past. We understand that this will drive the need for dynamic simluations because steady state simulations will not suffice.
Yes
Some are, some are not. Some we can prove, some we don't know and can't find out. With no experts to evaluate turbine under/over frequency in our company and turbine manufacturers either out of business or unwilling to provide turbine limits, is there any possible exception allowed for settings inside the no trip zone? Also, for existing turbines, we believe that the turbine blade conditions would have to be evaluated to make a judgement on how to shift the withstand. How can we be sure that we are not stressing our turbine if we set our devices outside of the curve in the standard? Can question 3 be addressed quantitatively? Instead of "100% on voltage", it should be "0%". Auxiliary systems are not included in the standards scope

as drafted. 100% on voltage (can't prove - auxilliary system) Unknown on frequency
40,000MW voltage, Unknown frequency
No
Controversy of Voltage cumulative nature, not showing the 95%-100% generator terminal voltage, difference between the curve being on the tranmission side of the GSU and the generator relay being on the generator side of the GSU. The generator terminal voltage shown at 95%-105% listed in R2.1. We are concerned that future auditors will interpret this limit as being the coordination limit. The voltage curve of Attachment 2 is stated for system voltage; however as mentioned in the conference call, the volts per hertz protection was specifically referenced and used to support setting criteria. We have a problem with this approach since the V/HZ relay is looking at the generator voltage and the curve is shown for the system voltage. How do we demonstrate coordination since the two are on different basis which cannot accurately be resolved via steady state techniques? The wording used in section R2.2.1 is confusing. The words should be changed to "For three-phase transmission system zone 1 faults with Normal Clearing, generator relaying shall be set longer than the expected fault clearing time, but does not have to be set for greater than nine cycles."
No
The unit size and plant size seem to be conservatively small. From a practical standpoint, our focus in this standard should be on the largest units, those that are most cricital in the reliability. A more reasonable limit would be 100MVA generator units and 200 MVA for multiple units at a single site.
Yes I agree with the approach
No
The VRF levels should range from low to high based on size of unit. Low risk 100-200MVA. Medium risk 200-500 MVA. High risk >500MVA.
No.
Nuclear Plant Requirements may conflict.
Yes
1. We recommend deleting the proposed section R2.2.2. If not deleted, change "meet a shorter voltage ride through" to "meet a less stringent voltage ride through". 2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field. 3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request" 4. How did the SDT translate the transient voltage excursion plot to the cumulative voltage curve? 5. The voltage ride through curve was said to be cumulative â€“ this should be specified on the curve. 6. How can we prove that our static voltage curve coordinates with this cumulative curve? 7. Implementation schedule â€“ we believe that the unit size should be considered, and that the most critical units should be worked on first. Completing 33% each year is too ambitious for those members that have > 300 units. 8. What regions are working on voltage ride through and Underfrequency (ufls and undefrequency tripping of generators)? 9. Should the PRC-024 SDT wait until the regions have completed their work? 10. Generator engineers do not see a relevence for a voltage ride-through for any generator other than wind.
Group
Kansas City Power & Light
Tim Hinken
Kansas City Power & Light
Yes
No
In many cases the exciter voltage regulator includes generator protective functions (for example, Basler DECS 300, DECS 400) such as Volts/Hertz, undervoltage, overvoltage, underfrequency that will also trip the Unit. These functions are usually set slightly above the trip settings of the equivalent generator protective relaying, but to not include them in this requirement would effectively nullify the stability effort sought by this requirement.
Yes
There are a number of generating units that currently have relay settings outside the proposed underfrequency and overfrequency relay settings. It is not known at this time if it is possible to adjust the settings within the proposed relay settings. 50%
1900 MW
No
R2 specifies that the generator may not operate on V/Hz evaluated at nominal frequency. Some generators have specific requirements to trip on V/Hz at 110%. This is in conflict with the upper

boundry point of Attachment 2 for times greater than 1 second. We recommend to change this requirement so that it does not apply to V/Hz settings. It is not practical to set generator protective relays fed from generator potential transformers to meet the voltage requirement at the point of interconnect to the BES. We recommend that the voltage chart requirement be applicable to the voltage measured by the generator protective relays, not the voltage at the point of interconnect to the BES.
Yes
Yes I agree with the approach
No
What is the basis for the MVA levels proposed by the standard here?
Not aware of any regional differences.
Not aware of any conflicts.
Yes
Please consider including the Balancing Authority as an entitiy for the Geneator Owner to provide settings information in requirements R3 & R4 since the BA is an entity that has a direct relationship with the operational status of generating stations. R5: Do not agree with the bulleted item where increasing the capabilility of a generator by 10% is a reason for exemption expiration. As an example, turbine or boiler enhancements can result in greater effeciencies and resulting in an increase of generator capability with no change to the generator or its protection capabilities whatsoever. Recommend removal of this bulleted item. R5: The generator exciter voltage regulator contains protective relay settings such as Volts/Hertz, undervoltage, overvoltage, underfrequency that will also trip the Unit. Is the exciter voltage regulator considered to be part of the generator protective relay system? If so, would a limitation of the exciter voltage regulator be allowed as an exception to the standard or, since the protective system is excluded, would R5 mandate that the excitor voltage regulator be replaced to remove the exception? This issue should be clarified in R5.
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
Yes
The Generator Owner is the Functional Model entity that has direct control over the generating unit protection settings.
No
The proposed standard addresses all issues identified in the Standard Authorization Request. Coordination of generator and transmission system protection is addressed in PRC-001. As presently constituted this Standard will likey result in the inappropriate enabling and setting of frequency and voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to its stated purpose. This is supported in the comments provided below. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Yes
A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
No
The curves should be revised based on generator capabilities and design requirements rather than the expected system response for simulated disturbances. Although the simulation results and tools used to develop the curves have not been provided it appears that the proposed curves are based on transient stability simulations. The transient stability program includes only the positive sequence component of system voltage and neglects phenomena that do not result in significant shaft torques. By contrast, protective relays measure individual phase or phase-to-phase quantities or in some cases specific sequence quantities. As proposed the curves may be interpreted differently in relay applications to the detriment of bulk electric system reliability and customer service. Since the curves will be used to set protective relays they should be based on the quantities that are measured by protective relays and the quantities should be clearly stated. We have provided examples of how the curves could be misinterpreted or misapplied if the curves are not constructed in terms of measured relay quantities and settings specific to the point of measurement: â€¢ Based on the proposed curve an overvoltage relay can be set at 120% with no intentional time delay. If this relay measures phase-to-ground voltage at the Point

of Interconnection (POI) then for a close-in line-to-ground fault the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault (effectively grounded system), resulting in undesired generator tripping prior to clearing the fault from the transmission system. â€¢ Protection against overvoltages that are shorter in duration than the operating time of circuit breaker is provided by surge arresters on the high-voltage terminals of the transformer and by surge protectors on the terminals of the generator. The curve implies that for a voltage of more than 120% that the generator can trip instantaneously (without intentional time delay). We suggest that instantaneous trips at any voltage level are neither required nor effective for generator protection. The overvoltage curve should approach zero time asymptotically or alternatively 250% for 20ms, 135% for 300ms, 120% for 20 seconds, 110% continuously. Alternatively the curve should be based on generator capability rather than FERC 661A which is applicable to wind generators with very limited capability. â€¢ In the undervoltage region the 9 cycle zero voltage has been carried over from FERC 661-A which is to facilitate wind integration. The 9 cycle zero voltage ride-thru, although less than prior utility designs, may be sufficient. We again recommend that SDT translate the intended positive sequence values to phase quantities measured by the relay to avoid misapplication. A single-line-to-ground fault will result in a positive sequence voltage of approximately 0.5-0.7pu but the voltages on individual phases or between phases may be quite different. The curve appears adequate from a positive sequence perspective but may not be interpreted as intended. â€¢ In the undervoltage region we recommend that 85% be applied from 3 seconds to 15 seconds to ensure that generators stay connected longer than load and to permit time for automatic reactive element switching. There is no reason to trip this fast in this region Based on the proposed curves we are concerned that the SDT has considered only the system response to typical design contingencies and only the positive sequence voltage from transient stability simulations. Although we have suggested alternate values the final values will depend on how the curve is defined, the form of measurement and relay application. As proposed we believe the curves leave too much for misinterpretation and misapplication. We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following: > In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a malfunction. > The existence of a curve such as this in a NERC Standard will lead to generators enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability. > For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate. > The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines. > The minimum voltage for 9 cycles does not allow enough time to allow for breaker failure protection operation. 13 -15 cycles would be appropriate. > The voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings. > Machine Volts per Hertz curves are a significant issue and are not addressed. > The UV performance of plant auxiliaries is a significant issue, and is not addressed. > We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard.
No
Reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage. We are concerned that the generator unit capacity thresholds are set too high. Given the tolerances in UFLS program design, the unit capacity thresholds should be established to ensure that 99 percent of the generation in a system complies with the requirements of this standard. The SDT should identify unit capacity thresholds on this basis, similar to how thresholds were developed in MOD-026. The interconnection voltage is not relevant, only the amount of generation potentially lost to the system. Some sub-regions, employing a UFLS Program, are dependent on Generator Owners/Operators meeting the specifications for generator Underfrequency setpoints in order to maintain a viable UFLS Program. For sub-regions where a large percentage of the total generation fleet is comprised of individual units < 20 MVA and connected to buses < 100 kV, the contribution of these units to the overall success of the sub-regions UFLS Program are more pronounced. It is suggested that the threshold should be established by refering to the requirements of the Region or as established by the Reliability Coordinator (sub-region). As an alternative, it is suggested that all generating units operating in a Reliability Coordinators' or RTO/ISO's market system, regardless of size, shall follow this Standard based on their materiality to the reliability of the bulk power system.
No I disagree with the approach
Given the potential impact on survivability of an island, and the need to lower the unit capacity thresholds for which this standard is applicable, as recommended in the comment to Question 5, it is suggested that the folowing Violation Risk Factor thresholds be applied: High > 100 MVA

Medium > 20 MVA and < 100 MVA Lower < 20 MVA Given the potential impact on survivability of an island, and the recommendation in our response to Question 5 to lower the unit capacity thresholds for which this standard is applicable, we recommend the following Violation Risk Factor thresholds: High >100 MVA Medium > 20 MVA and â‰¤ 100 MVA Lower â‰¤ 20 MVA
No
Given the potential impact on survivability of an island, and the need to lower the unit capacity thresholds for which this standard is applicable, as recommended in the comment to Question 5, it is suggested that the folowing Violation Risk Factor thresholds be applied: High > 100 MVA Medium > 20 MVA and < 100 MVA Lower < 20 MVA Given the potential impact on survivability of an island, and the recommendation in our response to Question 5 to lower the unit capacity thresholds for which this standard is applicable, we recommend the following Violation Risk Factor thresholds: High >100 MVA Medium > 20 MVA and â‰¤ 100 MVA Lower â‰¤ 20 MVA
Yes, the Québec Interconnection, within the Eastern Interconnection, would need different settings than the ones depicted in the Attachment 1 to coordinate with its UFLS program. We are also aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service. We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicted upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service.
Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.
Yes
Referencing R5 and R6 of the Standard: The Reliability Coordinator should be give veto power over exceptions to the requirements herein. Should the Generator Owner/Operator not be able to, or be unwilling to, make changes to setpoints to come into compliance with this Standard, the Reliability Coordinator should be given the authority to invoke required mitigation, such as requiring the Generator Owner/Operator to contract for compensatory load shedding up to the total amount of MW of each generating unit that fails to comply with the required setpoints. In addition, The "Off-Nominal Frequency Capability Curve" in Attachment 1 does not coordinate with the underfrequency load shedding (UFLS) program design parameters proposed by the NERC Underfrequency Load Shedding Standard Drafting Team for Project 2007-01. The misccoordination occurs in the time range approximatley between 5 and 10 seconds. This miscoordination can be eliminated by extending the horizontal line at 57.8 Hz to 5 seconds and revising the diagonal line to have endpoints at 57.8 Hz/5s and 59.5 Hz/1800s. This modification will provide coordination with the UFLS program design parameters while still maintaining coordination with turbine-generator capability. Due to the time scale on the graph in Attachment 2, the curves do not indicate the time at which the transient overvoltage and undervoltage requirements end, at which point the continuous voltage requirements would be applicable. Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above: > Concerning Attachment 1, we believe this is mainly present to infer that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled. > A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed â€¦ relaying not to trip during â€¦" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer. > Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted." > Concerning A.R2, this Standard addresses setting of voltage relays based on

voltage at the point of interconnection, which is not directly translatable to voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard. We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that " For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected " We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system undervoltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator? (2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations?
Group
MRO NERC Standards Review Subcommittee
Michael Brytowski
MRO
Yes
Yes
No
The MRO does not own any generation.
Yes
Where would be the appropriate voltage measurement point? (Generator bus or POI)
Yes
Yes I agree with the approach
Yes
If a region has performed a detailed system study of the Under Frequency protection systems in their region and developed protective settings based off the characteristics developed in the study, the region should be allowed to deviate from the Generator Protection curve in Attachment 1.
No known conflict at this time.
Yes
It would be good to have the option of measuring the voltage at the Generator bus or POI. With the understanding that the voltage must be maintained of the POI.
Individual
Mark Thompson
AESO
Yes
In addition to the SRC ISO/RTO comments the AESO would like to add: As we understand it, the intent of this standard is to ensure that the generators ride through certain levels of frequency and voltage excursions, yet it only addresses the generator protection. We feel it must also address the protection and capabilities of the auxilliaries, unit transformers, lines, etc. If any of these trip off due to the same excursions that the generator is required to ride through, then the generator will be down and the standard will not have achieved its goal.
Individual

James H. Sorrels, Jr.
American Electric Power
Yes
Yes
It is appropriate to limit the scope of this standard to setting of voltage and frequency generator protective relays, but it should be noted that other factors may cause generators to trip as a consequence of voltage or frequency excursions besides voltage or frequency sensing relays. An example is tripping due to complications involving over-excitation protection. Are other factors addressed elsewhere?
No
Yes
Yes
The applicability appears to be from the NERC Compliance registry. This is probably okay for the requirement on voltage related tripping, but the impact of frequency related tripping is not restricted to the BES as it likely would be with voltage tripping. A separate single-size applicability, independent of BES/non-BES connection, may be more appropriate for the frequency tripping requirement.
Yes I agree with the approach
No
The MVA levels appear to be arbitrary. What is the basis that the SDT used to establish these MVA thresholds?
No known regional variances
No known conflicts
No
Individual
Greg Rowland
Duke Energy
Yes
No
Footnote 1 is unclear and too broad. As stated, it includes voltage regulators - which is beyond the scope of this standard. Take voltage regulator out, or specify the volts per hertz protection function only.
Yes
15% of system capacity
Approximately 4000 MW
Yes
The applicability of the curve is limited to the protective relays addressed by the standard. This curve is not meaningful if the plants were going to trip due to other causes. See our response to Question #9.
Yes
No I disagree with the approach
It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH.
No
It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH.
None
None
Yes
The issue typically addressed by international grid codes is an over-all plant performance standard and plant dynamic studies are perfomed to evaluate the impact on in-plant systems. Standards applicable to only generator protection might give a false sense that a plant could

survive the transients and the reliability of the BES would be just as adversely impacted if large plants were to trip for causes other than a main generator relay. The basis and reliability benefit for voltage ride through transients should be clarified. Generator UF relays must coordinate with grid UFLS relaying. Some areas may apply UVLS and logic dictates that the coordination of that protection with a generator ride through criteria should be specified. Recommend that the scope of "equipment" that can be granted an exception be limited in some way or explicitly qualified. Otherwise, plant performance can be dictated by less-consequential auxiliary equipment (e.g. variable speed drives with UV settings per manufacturer standard instructions). Because R5 grants exception automatically in response to the GO providing documentation of any limitation. R5 bullet 2 - recommend changing "generator nameplate capacity rating" to "generator gross Real Power capability". The existing words are too general and including 'nameplate' is confusing.
Individual
Gregory Campoli
New York Independent System Operator
Yes
No
As presently constituted this Standard could result in the inappropriate enabling and setting of frequency and Voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to it's stated purpose. This is supported in the comments provided below. It would have been much more important to require that Voltage and frequency relays be applied only when they are required for machine protection, which this Standard does not do. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems on auxiliary systems, problems which arise due to low Voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Yes
A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
No
We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following: > In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a situation or malfunction which results in low voltage. > The existence of a curve such as this in a NERC Standard will lead to some generator owners enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability. > For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate. > The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines. > The minimum Voltage for 9 cycles does not allow enough time for breaker failure protection operation. 13 -15 cycles would be appropriate. > The Voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings. > Machine Volts per Hertz curves are a significant issue and are not addressed. > The UV performance of plant auxiliaries is a significant issue, and is not addressed. > We suggest that ANSI/IEEE Standards C37.102, C50 12, and C50.13 should be used and listed as references to this Standard.
No
The interconnection Voltage is not relevant, only the amount of generation potentially lost to the system.
Yes I agree with the approach
Yes
Yes
Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above: > Concerning Attachment 1, we believe this is mainly present to insure that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability"

in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled. > A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed â€¦ relaying not to trip during â€¦" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective device, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and Voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer. > Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this questions will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted." > Concerning A.R2, this Standard addresses setting of Voltage relays based on Voltage at the point of interconnection, which is not directly translatable to Voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard.
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
Yes
Yes
However, it should clearer in the requirements how mechanical and electrical overspeed protection is coordinated with the UF relay settings. Also, we would appreciate the SDT's view on why the frequency requirement are not being written into the existing PRC-006 (UFLS) standard.
No
A possible concern would be the effect on auxiliary system equipment and reliability at voltages below 90%.
Yes
Yes
Yes I agree with the approach
A suggestion for SDT's consideration is that VRFs could be based on percentage of units not in compliance. A utility may have several large units (high VRF) and many small (low VRF) not in compliance.
Yes
This standard may need to be coordinated with current efforts to revise standard PRC-006-1, and with the Regional standards being developed for UFLS, such as RFC's PRC-006-RFC-01.
Yes
1. FE's consensus is that the PRC-024 allowable under-frequency vs. time tripping curve is too tight. By too tight, we mean that the LP turbine buckets and blades are much more tolerant of off freq operation than the proposed tables. Comparing them to the old ECAR curves and allowable tripping times shows they are more stringent. Given how seldom these events occur, (never happened yet in the Eastern Interconnect) expending more of this capacity appears justified. 2. Section A5 Implementation schedule - it may not give sufficient time to implement these requirements. We suggest an additional year as follows: no less than 33% within 2 years of effective date no less than 66% within 3 years of effective date no less than 100% within 4 years of effective date 3. R1.2 Should say off-nominal not off-normal. 4. R2.1 Suggest changing the word "measured" to "experienced". 5. In R5, we suggest changing the first bullet to read: "The equipment causing the limitation is modified, upgraded or replaced with equipment that removes the technical limitation.", and then delete the second bullet. 6. Requirements 3, 4 and 6 specify that the Generator Owner shall provide information to RCs, PCs, TOPs, and TPs that monitor or model the associated unit; however, there is no requirement for these entities to identify

themselves to the Generator Owner. How will the Generator Owner know they have identified all of the entities that need the information? 7. In R5, the Generator Owner is granted an exception from requirements R1 or R2 simply by providing documentation of a equipment limitations. There is no independent view of the appropriateness of this exception. The drafting team should consider requiring independent verification of the equipment limitation prior to the granting of an exception to the requirements of the standard. 8. Sec. D References - Is this intended to be part of the standard? If so, it would be helpful if it was linked to the white paper so that we can review it. 9. In Requirements R3 through R6, the SDT may want to consider adding the Transmission Owner as nother entity who may need this information. 10. R2.2.1 may need to be re-worded as it requires that protection trip in no greater than 9 cycles. We are not aware of a disadvantage to the system if the tripping takes longer than 9 cycles.
Individual
Alice Murdock
Xcel Energy
No
We feel the GO would only be applicable for R6 and for when a new unit is being built. Once a unit is online, it is the GOP that would be performing all the actions to ensure compliance with R1-R5 of this standard. We also forsee compliance issues with jointly-owned units, if applicability were to remain only with the GO.
Yes
Yes
Please clarify if there is an expectation/requirement for new units to install voltage and frequency protective relays.
Individual
Armin Klusman
CenterPoint Energy
No
a) CenterPoint Energy does not agree with limiting the application of this standard to the few relays that the SDT has chosen to address (only generator under or over voltage protective relays and volts per hertz relays). In effect, the SDT is allowing possible tripping of generation during off nominal frequency and voltage excursions from several other types of relays and control systems. This may not provide adequate reliability, as loss of significant generation can occur for voltage sags. b) The SDT has not included generator backup over current, impedance, and loss of field relays within the scope of this draft standard. CenterPoint Energy believes these additional relays should also be addressed. CenterPoint Energy believes it is illogical to have a transmission relay loadability standard (PRC-023 â€˜Transmission Relay Loadabilityâ€™) based on current and impedance ride-through while exempting generators from comparable requirements. Such an exemption defeats the purpose of the transmission relay loadability requirements by allowing a system event to escalate due to failure of generator relays to ride-through the same types of events envisioned by PRC-023 requirements. One key purpose for PRC-023 is to â€œnot interfere with system operatorsâ€™ ability to take remedial action to protect system reliability.â€ c) In addition to including other types of generator relays, the relaying and control for plant auxiliary systems should also be addressed for operation during off nominal frequency and voltage excursions. Again, it is illogical to have a transmission relay loadability requirements based on current and impedance ride-through while exempting a generation plant from comparable requirements. CenterPoint Energy realizes that generating plants have many internal control systems on auxiliary equipment that could be impacted during low voltage events, but exempting such systems from this standard defeats its purpose. CenterPoint Energy also recognizes that failures or incorrect operation of equipment installed for voltage ride-through capability on auxiliary equipment controls, such as UPS devices, will occur. Therefore, CenterPoint Energy recommends the SDT specifically address plant auxiliary equipment ride through. CenterPoint Energy suggests that the requirements be similar to those in NERC standard PRC-004 â€˜Analysis and Mitigation of Transmission and Generation Protection System Misoperationsâ€™. That is, if the plant incorrectly trips during a voltage sag due to

auxiliary systems problems, the problem will be investigated and, where necessary, a system-wide corrective action plan will be developed and completed.
No
a) Attachment 2 of PRC-024-2 is truncated at 4 seconds and does not define the duration of the 0.9 pu voltage level. CenterPoint Energy recommends the total duration of the 0.9 pu voltage level be established at a MINIMUM of 10 seconds. The basis for 10 seconds is for coordination with undervoltage load shedding (UVLS) systems. b) Attachment 2 has a step function profile. CenterPoint Energy has reviewed these proposed steps for voltage recovery to 0.9 pu and concurs with most proposed steps. However, CenterPoint Energy studies indicate an insufficient coordination margin at the proposed 0.30 seconds at 0.65 pu voltage point. Noting the CenterPoint Energy transmission grid is a compact and stout system, CenterPoint Energy believes it is highly unlikely many transmission systems can recover to a 0.65 voltage level in 18 cycles (0.30 seconds). To address this, CenterPoint Energy recommends reducing the number of steps. For this, as well as including a 0.9 pu voltage level ride-through for a minimum of 10 seconds, CenterPoint Energy recommends the data points (Time / Voltage) in the â€œLVRT DURATIONâ€ table be as follows: 0.15 / 0.000, 2.00 / 0.450, 3.00 / 0.750, and 10.00 / 0.900.
Yes
a) CenterPoint Energy is concerned with what appears to be a lack of consistency and coordination between standards efforts. Considering PRC-023, CenterPoint Energy believes it is illogical to have transmission relay loadability requirements based on 0.85 pu system voltage for an extended period (such as, 15 minutes) to allow system operators to take remedial actions, while exempting generators from comparable requirements. For another example, it appears this proposed standard is not consistent with that being proposed for under-frequency load shedding systems that can help prevent cascading outages. b) Requirements, such as R2.2.1 and R2.2.2, are essentially fill-in-the-blank, location-specific criteria that are unnecessary and could have unintended consequences. Location-specific criteria can change over time with additions and modifications of the transmission system. Entities will have no incentives to voluntarily exceed the minimum required criteria, even though their plant has a greater ride-though capability. R2.2.1 further allows relaying to â€œbe set on actual fault clearing timesâ€, instead of the 9 cycles indicated in Attachment 2. In addition, R2.2.2 allows the use of location-specific criteria, but only if such criteria are less stringent. CenterPoint Energy believes NERC reliability standards should not include fill-in-the-blank, location-specific criteria. CenterPoint Energy recommends modifying R2.2.1 to reference Attachment 2 and to clarify the ride-through criteria is zero voltage for 0.15 seconds (9 cycles). CenterPoint Energy recommends deleting R2.2.2. c) R5 allows generating plants to meet less stringent criteria if generator manufacturer literature indicates limitations, which would further erode system support from generation resources. It does not appear there is any process to substantiate the legitimacy of such limitations. CenterPoint Energy recommends deleting R5 and associated references.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
We agree. This is consistent with our view expressed for MOD-026 for which we suggest the Generator Owner, not the Generator Operator, be held responsible for generating unit equipment/device settings and data verification.
Yes
We agree that it is a good start. However, other settings such as those mentioned in the Background Information Section (generator backup over current or impedance, loss of field, etc.) also give rise to tripping of the generator. Consideration should be given to expanding the scope of the SAR to include these settings. The lack of a standard for generator out-of-step protection resulted in adverse effects on the Michigan-Ontario ties during the 2003 blackout.
We are unable to comment on how many generating units in the fleet that are not capable of meeting the threshold in the Attachments since we are not a Generator Owner. However, we are unclear on the basis of the 57.8 Hz setting stipulated in R1.3 as it is not consistent with the proposed UFLS characteristics (posted in July of 2008) in which it indicates that frequency should be arrested at no less than 58.0 Hz. Further, the basis for the very restrictive over-frequency curve proposed in attachment #1 is not obvious. The over-frequency standard proposed in PRC-024 was exceeded during the blackout of 2003 for Ontario generation that was connected radially

into New York. No adverse effects attributed to this over frequency event have been reported to the IESO.
No
Simulation results only add value when sufficient validation has been performed to provide confidence that good decision can be made on the basis of these simulations. Simulations by themselves are not enough. Were the simulations used in this exercise validated against actual performance? To cater for protection differences within jurisdictions, it would be better to label the jogs in the voltage characteristic with the corresponding physical meaning (e.g. maximum normal fault clearing, maximum delayed fault clearing) rather than assign specific times. Within Ontario, it is unclear whether the voltage curves are sufficient to accommodate present practice for delayed fault clearing. It is unclear in the curves whether the POI voltage is the positive sequence voltage or phase voltage. The meaning of per unit should also be clarified. For example, Ontario uses a 220kV voltage basis for a system operated as high as 250kV. Does 1.2PU mean 264 kV or 300kV? The over-voltage settings should be re-expressed to ensure the short duration over-voltages that follow lightning strikes and capacitor switching do not result in generator tripping.
No
In an islanded situation, each generator's status is critical to ensuring frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not holding the smaller generators subject to the requirements associated with generator frequency tripping exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.
No I disagree with the approach
Size dependent VRFs do not reflect the potential reliability risk associated with more than one Medium size generating unit (>100 MVA and <500 MVA) failing to comply with the standard. Two of such units at, say, 400 MVA each, that trip unnecessarily will have a greater collective impact on the island frequency than the tripping of a 500 MVA unit.
No
Please see above comments. We suggest that the same VRFs apply to all units that meet the Applicability criteria.
None
None
Yes
a. R5: The wording "â€¦the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation." is not written in a way to hold an entity responsible for any action. We suggest to reword it such that it places a responsibilility to the Generator to seek approval for an exception, as follows: "â€¦the Generator Owner shall obtain approval for an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation through the submission of documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit within 30 days of identifying the equipment limitation." The requirement for getting non-conforming protection approved should be so stipulated to put the onus for mitigating actions on the Generator Owners. For example, in the case of non-conforming underfrequency settings, the requesting Generator Owner should be required to demonstrate that mitigating (i.e. arrangements for additional compensating load shedding) measures have been arranged with the Balancing Authority in their submission. Equipment settings that infringe upon the curves may be implemented only after approval is granted by the appropriate entities. Along with this proposed change, there is also a need for the entities receiving the approval request to respond to the request. Another requirement is needed to complete this process. b. The latter part of R5 should be reworded to hold an entity responsible for the needed actions associated with expiring the exception such that the requirement is measurable and enforceable. c. R6: It is unclear to us what purpose this requirement serves. If R5 is to be revised as we suggest (see above), then the "limitation" in question will be presented with technical justification in the request for approval. The receiving entities (RC, PC, TOP and TP) will have a chance to accept or reject the request with due consideration of the technical argument. This is part of the approval request process, hence we do not see the need for R6 if R5 is to be reworded. If a remand process needs to be stipulated, then inclusion in R5 a requirement for the receiving entity(ies) to respond to the request - either approving or disproving the with a rationale, would suffice.
Individual
Kirit Shah

Ameren
Yes
None
Yes
Please clearly state that such relays do not have to be added or elements enabled, GO makes the decision what protection to include. R1 and M1, and R2 and M2 should allow for proof that the frequency and/or voltage relays are omitted or set to alarm only, not trip. Please clearly define 'point of interconnection' used in 4.2.2; typically this is where the generating source connects to the switchyard or networked transmission system but these relays are typically at the generator terminals on the low side of the generator step-up transformer.
Yes
We have not yet performed a detailed review wrt proposed limits, but expect there will be some that are not capable of meeting these stated thresholds. It can be hard to get capability data and warranties have expired, for older units or those purchased from other owners. The PRC-024-1 curves should not become a de facto requirement. If decades of operating experience have proven satisfactory from both a BES and generator equipment life persperctive, this should be accepted as evidence as well. Generic guidance, such as past ANSI/IEEE standards, recommended practices, and guides should be allowed for older units exception evidence as well. Clearly state that field testing is not required.
No
FERC 661-A applies to wind generator Voltage Ride Though (VRT) for a three phase fault. We disagree with PRC-024-1 now expanding it to all generators. R2.2.1 wording is confusing: it implies that the UV trip setting must be less than 9 cycles which conflicts with the LVRT curve and its interpretation for lessor voltage dips.
Yes
Again from our perspective, the main objective is allow UFLS/UVLS to do their job to arrest frequency/voltage decline and retain generation on-line so as not to exacerabate the extreme disturbance. Of course, generation equipment limits must be respected. This standard should not encourage GO to augment protection or become more conservative than warranted, possibly refuting the main objective. We formerly belonged to the now defunct MAIN region. Previous MAIN requirements for generators were: Generator UF Setting (Hz) Minimum Time Delay (Sec) > 59.5 Hz Automatic tripping not permitted < 59.5 to > 59.2 Hz 2700 seconds < 59.2 to > 58.5 Hz 120 seconds < 58.5 to > 58.0 Hz 15 seconds < 58.0 Hz Ownerâ€™s Discretion We have applied these to generation that has connected in the last decade unless the GO had manufacturer recommendations to the contrary.
No I disagree with the approach
Are they based on the individual unit or the aggregate at the Point of Interconnection? Average annual production (MWh) is a better indicator of their threat to the BES during UF or UV events. Larger units should not be penalized just because they are large. If large and generating many MWh then they're big and likely to be on-line for an event.
No
See above
It seems that geography (e.g. peninsulas, coastal areas) and load sparcity, and dense load served by distant generation have been significant factors in blackout events. As such, regional differences do exist.
Nuclear Plant Requirements may conflict. Footnote 2 refers to the agreements for which the GO is not responsible. Also, grandfathered generation of more vertically integrated entities and/or in certain states may not have such formal agreements.
Yes
This standard could be ineffective if someoneâ€™s auxiliary power protection trips out on low voltage or frequency and brings the unit down before the generator protection. Those settings on the aux buses are there to protect the equipment from failure since most of the downstream loads such as motors and electronics wonâ€™t ride through an excursion as well as large T/G sets. We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard. Reporting mechanism in R3 and R4 raises some commercial concerns. We prefer a secure repository of reporting to the RRO. Then only those who do have valid reasons for studies or monitoring could be granted access to the information. Footnote 1 expands 'protective relays' definition to include voltage regulator, etc. Instead state that only direct trip elements (functions) in the voltage regulator and exciter are included, if that's the intent. It should be made very clear.
Individual
John Cummings
PPL Energy Plus

Yes

PPL is concerned with the following concepts in the standard: 1) The standard applies equally to asynchronous and synchronous machines, salient pole and round rotor machines, photovoltaic, and other resources and as such the standard does not appear to recognize that these technologies respond differently to voltage and frequency excursions. 2) Better clarity of generator owner and transmission owner roles regarding changing existing fault clearing times is needed in the proposed standard. 3) R2.2 requires further clarity regarding relay settings. 4) R3 and R4 look the same. 5) The reference paper under Section D needs a thorough review by the industry.

Individual

Robert Jenkins

First Solar

Yes

No

The application of the standard to arrays of solar inverters is unclear. While the primary breaker can be set to comply with the standards, when the system voltage is driven to zero during the fault, the inverters will lose their phase lock and begin to shut down.

Yes

The response, and therefore compliance with this proposed Standard, are not clear. The standard does not seem to contemplate static power generators that would be part of renewable energy systems like solar PV. As part of the requirement there should be specificity on a number of points. For example as written it does not clearly define what the generator does during the out of frequency/voltage conditions. Presumably the inverters would not be required to drive current into the fault and thereby increase fault duties. Furthermore, once the fault is cleared, it does not define the speed/rate at which power is ramped up from the generator. This rate could be hard to achieve with a static converter. Finally, the standard does not define the rate of change of frequency or voltage. Typically devices are more sensitive to high rate changes. All of these items need more detail and specificity to determine how new forms of generation can meet these requirements.

No

See response to the previous question. While this may envelope the probable range of voltages that may occur on the system, it does not sufficiently describe the response of the generating plant to these disturbances. To simply say that the protective relays should not trip lacks sufficient detail to apply to inverter based PV projects.

The requirements are inconsistent with UL 1741 and IEEE 1547 as applied to existing solar PV inverter design. Compliance withn the proposed Standard would require an industry re-design and recognition from the Interconnecting Transmission Owner that projects would not meet these other standards. Additionally the Standard should provide for a phase in period for inverter based PV facilities so that such redesign can be accommodated.

Individual

Jay Seitz

US Bureau of Reclamation

Yes

We agree since PRC-004-1, Protection System Misoperation Analysis and Correction and PRC-005-1, Protection System Maintenance, are applicable to the Generator Owner (and Transmission

Owner); however, PRC-001-1 Protection System Coordination is applicable to the Generator Operator (and Transmission Operator). We believe all of the above should be coordinated and applicable to the Owner. The Standard also has a role for a Transmission entity (in this case the Transmission Planner) to specify clearing times; however no applicability or requirement is provided in the standard. We believe the role for a Transmission entity should be clarified in the Standard and applicability and requirement(s) added.
No
Now that the draft standard has been posted, it appears to be a more structured and limited version of existing Standard PRC-001-1 - System Protection Coordination. PRC-001-1 requires the Generator entity to coordinate protection settings with the Transmission entity. The stated Purpose of PRC-024-1 "Ensure that generator frequency and voltage protective relays are set to support transmission system stability during voltage and frequency excursions" should be attainable through PRC-001-1. If PRC-001-1 is not adequate it should be modified rather than adding an additional standard only addressing generator frequency and voltage settings. As such we do not believe there is a clear, reliability based justification for this standard as currently drafted.
No
No
The SDT background material above states that the 9 cycle time is required by FERC Order 661-A. FERC Order 661-A applies to wind generators. We believe there is no convincing reliability based rationale to expand the scope of the FERC Order via this standard to include synchronous machines, noting that Genrators are already required (PRC-001-1) to coordinate settings with the host Transmission Operator.
Yes
The threshold should be consistent with the NERC Reliability Compliance Registry Criteria.
No I disagree with the approach
If this approach is appropriate for this standard, it seems this approach should be used for all Standards applicable to generators.
Yes
Requirements R3 and R4 place a coordinating role on the Generator Owner to provide trip settings to four entities, the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner. We believe it is more appropriate for the Generator Owner to coordinate settings with a single Transmission entity since the purpose of the Standard is " ... to support transmission system stability during voltage and frequency excursions." and for the Transmission entity to further coordinate if necessary. The Transmission entity is in a better position to know what additional entities, if any should be involved. For the data points provided in the Attachment 2, HVRT DURATION and LVRT DURATION, we recommend both time and voltage units of measure be provided.
Individual
Jason Shaver
American Transmission Company
Yes
Yes
No
ATC does not own any generation
Yes
Yes
Yes I agree with the approach
Yes

No
t would be beneficial to have the option of measuring the voltage at the generator bus or point of interconnection (POI), with the understanding that the proper voltage must be maintained at the POI.
Group
IRC Standards Review Committee
Ben Li
IESO
Yes
We agree. This is consistent with our view expressed for MOD-026 for which we suggest the Generator Owner, not the Generator Operator, be held responsible for generating unit equipment/device settings and data verification.
Yes
We agree that it is a good start.
No
We are unable to comment on how many generating units in the fleet that are not capable of meeting the threshold in the Attachments since we are not a Generator Owner. However, we are unclear on the basis of the 57.8 Hz setting stipulated in R1.3 as it is not consistent with the proposed UFLS characteristics (posted in July of 2008) in which it indicates that frequency should be arrested at no less than 58.0 Hz. We also think the question is a bit misleading and may not result in providing the SDT any grounded suggestions or concurrence on the appropriate frequency levels that the SDT may already have in mind. The question as written suggests that the SDT is trying to canvass the industry through this commenting process. This is a way to obtain feedback, but it does not provide the rationale of the proposed levels. We suggest that the SDT research the limitations of the machines that are connected to the BPS (perhaps by a survey or a NERC data request) to better support the proposed frequency limit, then ask for concurrence or alternative suggestions.
Yes
From a system operator's perspective, we think these parameters are appropriate to prevent unnecessary tripping of the generators, which may otherwise give rise to unreliability, while minimizing their expose to prolonged period of under and overvoltages.
No
There should not be any exemption of the coordination on frequency trip setting. In an islanded situation, each generator's status is critical to ensuring that frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not holding the smaller generators subject to the requirements associated with generator frequency tripping exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.
No I disagree with the approach
Size dependent VRFs do not reflect the potential reliability risk associated with more than one Medium size generating unit (>100 MVA and <500 MVA) failing to comply with the standard. Two of such units at, say, 400 MVA each, that trip unnecessarily will have a greater collective impact on the island frequency than the tripping of a 500 MVA unit.
No
Please see above comments. We suggest that the same VRFs apply to all units that meet the Applicability criteria.
None
None
Yes
a. R5: The wording "â€¦the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation." is not written in a way to hold an entity responsible for any action. We suggest to reword it such that it places a responsibility to the Generator to seek approval for an exception, as follows: "the Generator Owner shall obtain approval for an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation through the submission of documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit within 30 days of identifying the equipment limitation.

Along with this proposed change, there is also a need for the entities receiving the approval request to respond to the request. Another requirement is needed to complete this process. b. The latter part of R5 should be reworded to hold an entity responsible for the needed actions associated with expiring the exception such that the requirement is measurable and enforceable. c. R6: It is unclear to us what purpose this requirement serves. If R5 is to be revised as we suggest (see above), then the "limitation" in question will be presented with technical justification in the request for approval. The receiving entities (RC, PC, TOP and TP) will have a chance to accept or reject the request with due consideration of the technical argument. This is part of the approval request process, hence we do not see the need for R6 if R5 is to be reworded. If a remand process needs to be stipulated, then inclusion in R5 a requirement for the receiving entity(ies) to respond to the request - either approving or disproving the with a rationale, would suffice.

Consideration of Comments on Draft Standard PRC-024-1 for the Generator Verification Standard Drafting Team — Project 2007-09

The Generator Verification Standard Drafting Team thanks all commenters who submitted comments on the proposed revision to the PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings standard. This standard was posted for a 45-day public comment period from February 17-April 2, 2009. Stakeholders were asked to provide feedback on the standard through a special electronic comment form. There were 43 sets of comments, including comments from more than 100 different people from over 60 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

For this report, the comments have been organized by question number so it is easier to see where there is consensus. The comments submitted can be reviewed in their original format on the following Web page:

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

The drafting team considered stakeholder comments and made the following changes based on those comments:

Purpose:
The drafting team revised the purpose to clarify that new generators must be capable of riding through voltage and frequency excursions and expected unit performance during frequency and voltage excursions must be communicated to entities that monitor or model the associated generator.

Applicability:
The drafting team has determined that only the Generator Owner has responsibilities required by this NERC Standard. The "facility applicability" language that duplicated the language from the Compliance Registry Criteria is not necessary to include in the applicability section of the standard, and was removed.

The team added a footnote to both Requirements R1 and R2 to clarify that the requirements in the standard do not require any entity to have frequency or voltage protective relaying installed or activated on its units.

Requirement R1:

- Modified the sequence of the wording in the requirement
- Replaced the range of VRFs based on MVA to a single VRF for consistency with other standards
- Added the following as an additional criterion under which the generating unit may not trip:
    - When the transmission system frequency rate of change is less than 2.5 Hz/second with a total change of up to 1.0 Hz.

Requirement R2:

- Modified the language to clarify that the intent is to address trippings associated with events external to the generator
- Added more specificity to each of the criterion under which the generator unit may not trip
- Replaced the range of VRFs based on MVA to a single VRF for consistency with other standards

Requirement R3 and Requirement R4 (now R7 in the revised standard)

- Merged these requirements and moved the requirement so that it is the last requirement in the standard so that the sequence of requirements has more of a chronological order

Requirement R5 (now R3 in the revised standard)

- Modified the sequence of wording in the requirement and simplified the language for greater clarity on the required documentation of equipment limitations..

Requirement R6 (now R4 in the revised standard)

- Modified the sequence of wording in the requirement and simplified the language for greater clarity.

New Requirement R5

- Requires Generator Owners to provide requesting entities with specific documentation to support an estimate of a unit's performance during Frequency/Voltage Excursions for modeling and study accuracy.

- This requirement addresses the inability of some existing units to ride-through the voltage and frequency excursions identified in Attachment 1 and 2. The purpose of this Requirement is to provide the Transmission Planner the ability to more accurately model generating plant performance during system voltage and frequency excursions.

New Requirement R6:

- Requires Generator Owners to have new generating units designed, built, and maintained so that they don't trip and do remain within specified parameters during frequency and voltage excursions associated with events external to the unit.

Attachments 1 and 2:

- The SDT developed the off nominal frequency curve (Attachment 1) in coordination with the NERC UFLS Standard Drafting Team. The 57.8 Hz setting for generator underfrequency and 58 Hz for UFLS is to ensure that the UFLS will have a chance to arrest the system frequency decline before reaching the minimum permissible frequency for generators. The intent of the curves is to ensure that the generators do not trip when the frequency is within the area bounded by the high and low frequency curves. When the frequency excursion reaches outside the high or low curve, the generator is allowed to trip.
- The SDT developed the off nominal frequency capabilities based on turbine manufacturers' capabilities in conjunction with the ability to set relays between the frequency curve and the manufacturers' curves.
- Updated Attachment 2 to add more clarity on the calculations for the 'voltage ride through curve.

The team made conforming changes to the measures and added compliance elements to the standard. If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 315 439 1390 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The PRC-024-1 Standard is applicable to the Generator Owner as opposed to Generator Operator, do you agree? If not, please explain in the comment area. 11

2. The SDT has established the Requirements in this Standard only for the setting of voltage and frequency generator protective relays. Do you agree? If not, please explain in the comment area. 17

3. PRC-024-1 specifies the limits for generator protective system settings as defined in PRC-024-1 - Attachment 1 and PRC-024-1 - Attachment 2. Are there generating units in your fleet that are not capable of meeting the thresholds in these attachments due to turbine/generator equipment design limitations? 29

4. The curve in PRC-024-1 — Attachment 2 was based upon analysis performed of simulated system disturbances. System voltage traces representative of several hundred disturbances were co-plotted on a voltage versus time graph. The voltage duration curve in this attachment is derived from these voltage traces. A margin was then applied to the voltage duration curve to account for unanticipated system conditions. The 9 cycle fault clearing time required by the FERC 661-A Order is incorporated into this curve. Given this background on the development of PRC-024-1 — Attachment 2, do you agree with the parameters of the curve? If not, please explain in the comment area. 40

5. Coordination between UFLS programs and generator frequency tripping is especially a concern in islanded situations. Is the connection voltage of >100kV, the size threshold for generator units 20 MVA and greater and 75 MVA for multiple units at a single site, sufficient to address this concern? If not, please explain in the comment area. 70

6. The SDT proposed a set of VRFs based on size delineation of units. Do you agree with this approach? Do you agree with the MVA levels? If you disagree with either the approach or the MVA levels, please explain in the comment area. 78

7. If you are aware of any regional variances that would be required as a result of this standard please identify the regional variance here. 89

8. If you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify the conflict here. 94

9. Are there other improvements that the SDT should consider for this revision of PRC-024-1 that you haven't already identified in response to other questions? If yes, please provide in the comment area. 98

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Stan Jaskot	Entergy Fossil Operations					X					
2.	Group	John Ciufo — SPCS	NERC System Protection and Control Subcommittee (SPCS)	X	X			X				X	X

Group 1 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jules Guillot	Entergy Fossil Operations	SERC	5
2.	Jamil Khan	Entergy Fossil Operations	SERC	5

Group 2 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Sykes Vice Chairman	Salt River Project	WECC	1, 5
2.	Michael McDonald	Ameren Services Company	SERC	1, 5
3.	William J. Miller	Exelon Corporation	RFC	1, 5
4.	George Pitts	Tennessee Valley Authority	SERC	1, 5, 9
5.	Sungsoo Kim	Ontario Power Generation Inc.	NPCC	5, 9
6.	See NERC SPCS Roster for more			

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Individual	Patrick Brown	PJM Interconnection		X								
4.	Group	Jalal Babik	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Whanger	F&H	SERC	5
2.	Chip Humphrey	F&H	RFC	5
3.	John Loftis	Electric Transmission	SERC	1
4.	Jack Kerr	Electric Transmission	SERC	1
5.	Lou Roeder	Electric Transmission	SERC	1
6.	Kirit Doshi	Electric Transmission	SERC	1
7.	Craig Crider	Electric Transmission	SERC	1
8.	Solomon Yirga	Electric Transmission	SERC	1
9.	Mike Garton	Regulatory	NPCC	5
10.	Louis Slade	Regulatory	MRO	6
11.	Jalal Babik	Regulatory	SERC	3
12.	Chris Funderburk	Nuclear	SERC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	David Kiguel	Hydro One Networks Inc.	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Company of New York	NPCC	1
5.	Brian L. Gooder	Ontario Power Generation Inc.	NPCC	5
6.	Mike Schiavone	National Grid	NPCC	1
7.	Robert Pellegrini	The United Illuminating Company	NPCC	1
8.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
9.	Randy MacDonald	New Brunswick System Operator	NPCC	2
10.	Greg Campoli	New York Independent System Operator	NPCC	2
11.	Kathleen Goodman	ISO New England, Inc.	NPCC	2
12.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
13.	Peter Yost	Consolidated Edison Company of New York, Inc.	NPCC	3
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Rick Foster	SERC Dynamics Review Subcommittee (DRS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Sujit Mandal	Entergy	SERC	1
4.	Venkat Kolluri	Entergy	SERC	1
5.	John O'Connor	Progress Energy Carolinas	SERC	1
6.	Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
7.	Lee Taylor	Southern Company Services, Inc. - Trans	SERC	1
8.	Robbie Bottoms	TVA	SERC	9
9.	Tom Cain	TVA	SERC	9
10.	Herb Schrayshuen	SERC	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Tim Hinken	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gammon	Kansas City Power & Light	SPP	1, 3, 5, 6
2.	Jerry Hatfield	Kansas City Power & Light	SPP	1, 3, 5, 6
3.	Nick McCarty	Kansas City Power & Light	SPP	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	4. Dan Jones	Kansas City Power & Light	SPP — 1, 3, 5, 6										
8.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Group 8 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MP	MRO	1, 3, 5, 6
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Terry Bilke	MISO	MRO	2
4.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Jim Haigh	WAPA	MRO	1, 6
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6
8.	Joseph Knight	GRE	MRO	1, 3, 5, 6
9.	Scott Nickels	RPU	MRO	3, 4, 5, 6
10.	Dave Rudolph	BPEC	MRO	1, 3, 5, 6
11.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
12.	Pam Sordet	XCEL	MRO	1, 3, 5, 6

Group 9 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Dave Folk	FE	RFC	1, 3, 4, 5, 6
3.	Mike Williams	FE	RFC	5
4.	Art Buanno	FE	RFC	1
5.	Ed Baznik	FE	RFC	1
6.	Ken Dresner	FE	RFC	5
7.	Bill Duge	FE	RFC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Anita Lee	AESO	WECC	2
2.	James Castle	NYISO	NPCC	2
3.	Matt Goldberg	ISO-NE	NPCC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Bill Phillips	MISO	MRO	2
6.	Charles Yeung	SPP	SPP	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Individual	Scott Etnoyer	Constellation Power Generation & Constellation Nuclear					X					
12.	Individual	Rick Terrill	Luminant Power										
13.	Individual	Hugh Francis	Southern Company	X		X		X	X				
14.	Individual	Jinhui Zhang	Converteam Naval Systems Inc.										
15.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					
16.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
17.	Individual	Brendan Kirby	AWEA								X		
18.	Individual	Mark L Bennett	Gainesville Regional Utilities	X		X		X					
19.	Individual	Michael Goggin	American Wind Energy Association								X		
20.	Individual	Cleyton Tewksbury	Veolia Environmental Services					X					
21.	Individual	Mark Ringhasuen	Old Dominion Electric Cooperative				X						

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Patrick Farrell	Southern California Edison Company	X		X			X				
23.	Individual	Barry Francis	Basin Electric Power Cooperative	X		X		X					
24.	Individual	Tony Kroskey	Brazos Electric Power Cooperative	X									
25.	Individual	Harianto Suryo	Lakeland Electric									X	
26.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
27.	Individual	D. Bryan Guy	Progress Energy, Inc.	X		X		X					
28.	Individual	Bob Shanks	NIPSCo	X		X		X	X				
29.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
30.	Individual	Rick White	Northeast Utilities	X									
31.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
32.	Individual	Mark Thompson	AESO		X								
33.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
34.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
35.	Individual	Gregory Campoli	New York Independent System Operator		X								
36.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
37.	Individual	Armin Klusman	CenterPoint Energy	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
38.	Individual	Dan Rochester	Independent Electricity System Operator		X								
39.	Individual	Kirit Shah	Ameren	X		X		X	X				
40.	Individual	John Cummings	PPL Energy Plus					X					
41.	Individual	Robert Jenkins	First Solar										
42.	Individual	Jay Seitz	US Bureau of Reclamation					X					
43.	Individual	Jason Shaver	American Transmission Company	X									

1. **The PRC-024-1 Standard is applicable to the Generator Owner as opposed to Generator Operator, do you agree? If not, please explain in the comment area.**

Summary Consideration:

A majority of responders commented that the relay settings are the responsibility of the GO with several respondents indicating that this Standard ought to apply to both the GO and the GOP.

The minority included comments as follows:

- The relay settings are the responsibility of the GOP
- Since the GOP does not own the generator, he cannot change the settings w/o GO approval
- The GO has the maintenance responsibility
- The GOP has the maintenance responsibility
- There will be complications for generators with multiple owners
- TP should be added to specify clearing times

The latest version of the Functional Model provides some clarity on the division of duties between the Generator Owner and Generator Operator. The Generator Owner has the responsibility for making decisions about the design and maintenance of generating facilities, including the generator protection systems: "Generator Owner Task 2: Design and authorize maintenance of generation plant protective relaying systems, protective relaying systems on the transmission lines connecting the generation plant to the transmission system, and Special Protection Systems."

The drafting team has determined that the Generator Owner has the responsibilities required by this NERC Standard. The Generator Owner requirements include following specified limits on protective relay settings, providing notification of changes to protective relay settings, documenting equipment limitations, and responding to comments from the RC, PC, TO, or TP on this subject.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Both bullets should be checked above (form will not accept).The responses received were divided, and below are the comments received for your consideration. The Generator Operators, and not the Generator Owners, are typically responsible for establishing relay setpoints, calibrations, and maintenance. The Generator Owner is the Functional Model entity that has direct control over the generating unit protection settings.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems. Please see the summary considerations above.		
Constellation Power Generation & Constellation Nuclear	No	The Generator Operators, and not the Generator Owners, are typically responsible for establishing relay setpoints, calibrations, and maintenance. The Generator Owner is the Functional Model entity that has direct control over the generating unit protection settings.
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems. Please see the summary considerations above.		
Converteam Naval Systems Inc.	No	I believe it should be applicable to both.
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems. Please see the summary considerations above.		
Gainesville Regional Utilities	No	In a number of smaller utilities, they are the same and do not need to be addressed separately
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems.		
Veolia Environmental Services	No	The generator operator is the entity charged with maintaining the facility. Therefore, the GOP has all the necessary records and procedures.
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems. Please see the summary considerations above.		
Old Dominion Electric Cooperative	No	I agree that the GO is the primary function for this requirement, but given the multitude of Go/GOP configurations out there, I think the GOP function should also be included in the applicability section of this standard.
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the		

Organization	Yes or No	Question 1 Comment
responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems. Please see the summary considerations above.		
Southern California Edison Company	No	The Generator Operator should be the functional entity to whom the standard applies because Generator Operators tend to change the settings without warning or permission.
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems. Please see the summary considerations above.		
Xcel Energy	No	We feel the GO would only be applicable for R6 and for when a new unit is being built. Once a unit is online, it is the GOP that would be performing all the actions to ensure compliance with R1-R5 of this standard. We also foresee compliance issues with jointly-owned units, if applicability were to remain only with the GO.
Response: Thank you for your response. The drafting team has determined that the Generator Owner is the appropriate party to fulfill the responsibilities required by this NERC Standard since the required actions are related to the design and maintenance of the protection systems. Please see the summary considerations above.		
Entergy Fossil Operations	Yes	Generator Owner is responsible for the maintenance of the facility. Relay settings are a Generator Owner function.
Response: Thank you for your response. The SDT agrees with your comments.		
SERC Dynamics Review Subcommittee (DRS)	Yes	Since the generator operator does not own the equipment addressed by the standard, he cannot change the settings without the generator owner's approval. The standard potentially requires changing the frequency and voltage relay trip settings. Since the generator owner owns the equipment, they also own the settings and should be the one held accountable for meeting the requirements of this standard.
Response: Thank you for your response. The SDT agrees with your comments.		
IRC Standards Review Committee	Yes	We agree. This is consistent with our view expressed for MOD-026 for which we suggest the Generator Owner, not the Generator Operator, be held responsible for generating unit equipment/device settings and data verification.
Response: Thank you for your response. The SDT agrees with your comments.		

Organization	Yes or No	Question 1 Comment
Southern Company	Yes	If the standard is in place, it belongs to the Generator Owner. The SAR seemed to be written for transmission, but this standard seems to be evolving to a generator setting standard. Does the SAR need to be revised? Although GO has the access to the equipment settings/records, GOP may not, GOP is the entity to operate the units. GO must communicate settings to the GOP. Since the generator operator does not own the equipment addressed by the standard, he cannot change the settings without the generator owner's approval. The standard potentially requires changing the frequency and voltage relay trip settings. Since the generator owner owns the equipment, they also own the settings and should be the one held accountable for meeting the requirements of this standard.
Response: Thank you for your response. The SDT agrees with your comments. The proposed requirements are within the scope of the SAR.		
Basin Electric Power Cooperative	Yes	I have some problems with the intent of this standard in general, but a standard of this nature would have to apply to the generator owner.
Response: Thank you for your response. The SDT agrees with your comment.		
Progress Energy, Inc.	Yes	Since the generator operator does not own the equipment addressed by the standard, he cannot change the settings without the owner's approval. The standard potentially requires changing the frequency and voltage relay trip settings. Since the generator owner owns the equipment, they also own the settings and should be the one held accountable for meeting the requirements of this standard.
Response: Thank you for your response. The SDT agrees with your comment.		
Hydro-Québec TransEnergie (HQT)	Yes	The Generator Owner is the Functional Model entity that has direct control over the generating unit protection settings.
Response: Thank you for your response. The SDT agrees with your comment.		
Independent Electricity System Operator	Yes	We agree. This is consistent with our view expressed for MOD-026 for which we suggest the Generator Owner, not the Generator Operator, be held responsible for generating unit equipment/device settings and data verification.
Response: Thank you for your response. The SDT agrees with your comment.		
US Bureau of Reclamation	Yes	We agree since PRC-004-1, Protection System Misoperation Analysis and Correction and PRC-005-1, Protection System Maintenance, are applicable to the Generator Owner (and Transmission Owner); however, PRC-001-1 Protection System

Organization	Yes or No	Question 1 Comment
		Coordination is applicable to the Generator Operator (and Transmission Operator). We believe all of the above should be coordinated and applicable to the Owner. The Standard also has a role for a Transmission entity (in this case the Transmission Planner) to specify clearing times; however no applicability or requirement is provided in the standard. We believe the role for a Transmission entity should be clarified in the Standard and applicability and requirement(s) added.
Response: Thank you for your response. The SDT agrees that the GO is the responsible party for PRC-024-1. Substantial rewriting of this Standard has occurred since the first posting, yet the TP has not yet been included in the applicability.		
NERC System Protection and Control Subcommittee (SPCS)	Yes	
PJM Interconnection	Yes	
Dominion	Yes	
Kansas City Power & Light	Yes	
MRO NERC Standards Review Subcommittee	Yes	
FirstEnergy	Yes	
Luminant Power	Yes	
Consumers Energy Company	Yes	
E.ON U.S.	Yes	
AWEA	Yes	
American Wind Energy Association	Yes	

Organization	Yes or No	Question 1 Comment
Brazos Electric Power Cooperative	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
NIPSCo	Yes	
Indiana Municipal Power Agency	Yes	
Northeast Utilities	Yes	
American Electric Power	Yes	
Duke Energy	Yes	
New York Independent System Operator	Yes	
Ameren	Yes	None
First Solar	Yes	
American Transmission Company	Yes	

2. **The SDT has established the Requirements in this Standard only for the setting of voltage and frequency generator protective relays. Do you agree? If not, please explain in the comment area.**

Summary Consideration:

Minority comments were wide-ranging and covered the following issues:

- Some respondents expressed that the Standard needs more technical justification.
- Generator protection relays are designed to protect generation equipment. NERC has no business dictating how Generator Owners or Operators protect their equipment. Reducing generator protection ultimately reduces power system reliability.
- Generator loss of life should be considered.
- This Standard should only apply to non-synchronous generators. PRC-001 or a new SAR will take care of synchronous generators. This Standard will encourage setting of relays that are not already set and reduce reliability.
- Setting all generator voltage trip points at the same point will result in catastrophic loss of generation.
- Other relays and devices should be included including Volts/Hertz, generator backup impedance, voltage restrained over-current, and exciter voltage regulator protective functions.
- Footnote 1 is too broad and the Standard should not address voltage regulators.
- Some locations do not need to include generators that are smaller than 100 MVA.
- Include formulas as well as the curves.
- Worst case conditions should be considered with extra margins allowed for oscillations. Generator frequency trip settings should be longer with UFLS normally reducing the frequency recovery time.

On the larger issue of performance, a significant number of respondents pointed that the SAR was clear in its scope and that the SDT should address generator plant performance and not merely propose a relay setting standard. In other words, the Standard should apply to all components of the generation plant. As originally written the Standard defeats the purpose of PRC-023 on transmission loadability.

A small dissenting minority expressed that the SAR's goal of having generators ride through voltage and frequency disturbances is not practical and that "generators" are not designed to ride through these events.

The GV SDT has determined that this NERC Standard should require new generators to ride through voltage and frequency excursions. The revised Standard does not dictate how generators should be protected. The revised Standard specifies the limits for events that new generators are required to ride through. These limits were developed based on manufacturers' information on machine capabilities as well as on power system reliability requirements. The Standard is a protective relay setting Standard for existing generators. Further, the GV SDT has included a provision for existing generators that cannot meet the limits specified in R1 and R2.

Organization	Yes or No	Question 2 Comment
Entergy Fossil Operations	No	I disagree in principle that NERC is dictating how generator protective relays are set. These relays are set to protect the generation equipment and ensure long term reliability of the unit. Dictating settings which enhances ride through capability ensure short term reliability and can hurt long term reliability. If this if force upon us, I agree with only addressing the voltage and frequency generator protective relays.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions. The Standard does not dictate how generators should be protected. The Standard specifies the limits for events that new generators are required to ride through. These limits were developed based on manufacturers' information on machine capabilities as well as on power system reliability requirements. The Standard is a protective relay setting Standard for existing generators. Further, the SDT has included a provision for existing generators that cannot meet the limits specified in R1 and R2.		
NERC System Protection and Control Subcommittee (SPCS)	No	PRC-024 should only apply to non-synchronous machines. The SPCS believes that coordination of synchronous generator voltage and frequency protective relays with transmission relays should not be addressed in PRC-024. An effort is underway to address coordination of generator voltage and frequency protective relay settings with transmission protection systems either by modifications to PRC-001 or the development of a new SAR to address coordination requirements. SPCS is preparing a Technical Reference paper on such coordination that is expected to be completed in June, 2009. Generator voltage and frequency protective relays are included in that that paper. The purpose as stated in the SAR is "To ensure that generators will not trip off-line during specified voltage and frequency excursions." The Standard will not accomplish its stated purpose by limiting requirements to generator protective relays alone. In fact it may actually have the exact opposite consequence. Undervoltage relays are not usually set on most synchronous generators. When undervoltage relays are applied, IEEE C37.102 recommends alarm rather than trip. The more likely cause for the loss of a generator due to a dip in voltage is from the loss of equipment on the auxiliary bus. This was the cause sited for a well documented event on March 27, 1994 losing all generating units at Cinergy's Gibson Station. Other events since 1994 were also due to tripping of generators due to loss of auxiliary busses caused by voltage dips from system faults. In fact, the Standard may result in the unintended consequence of reducing reliability. Many generator owners may take the recommendation as an implied directive to set previously unused generator undervoltage relay elements to the minimums stated in the Standard. That would cause more generator trips for system faults rather than fewer trips. Similarly, many generators that currently do not have undervoltage relay settings would trip at various other inherent voltage levels during a voltage excursion. With all of them set at or about 0.90 per unit, they would all trip at the same point, causing a catastrophic loss of generation. There are significant machine protection issues which are not addressed, such as the Volts/Hertz relay which protects the machine from an over-fluxing thermal hazard. Loss of generation consequential to problems on auxiliaries is a significant problem, which is not addressed in this Standard.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees with you that the previous version of the draft Standard "will not accomplish its stated purpose by limiting requirements to generator protective relays alone." The Standard has been modified to require new generators to ride through voltage and frequency excursions. The standard is technology neutral and applies to all generators. The SDT followed the SAR in applying the Standard to all new generators and by coordinating with the underfrequency load shedding Standard development.		
Northeast Power Coordinating Council	No	Both bullets should be checked above (form will not accept).The proposed standard addresses all issues identified in the Standard Authorization Request. Coordination of generator and transmission system protection is addressed in PRC-001.As presently constituted this Standard will likely result in the inappropriate enabling and setting of frequency and voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to its stated purpose. This is supported in the comments provided below. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Response: The SDT has modified the standard to address those relays that have frequency or voltage inputs that would directly trip the unit. The SDT has clarified that generators are not required to install or set the relays to trip. The Standard has been modified to address loss of generation consequent to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both.		
SERC Dynamics Review Subcommittee (DRS)	No	Settings for generator backup impedance and voltage restrained overcurrent relays need to be covered too. Their inclusion will provide complete coverage of the generator. There have been instances where these relays have operated in the past. We understand that this will drive the need for dynamic simulations because steady state simulations will not suffice.
Response: The SDT has modified the Standard to address those relays that have frequency or voltage inputs that would directly trip the unit.		
Kansas City Power & Light	No	In many cases the exciter voltage regulator includes generator protective functions (for example, Basler DECS 300, DECS 400) such as Volts/Hertz, undervoltage, overvoltage, underfrequency that will also trip the Unit. These functions are usually set slightly above the trip settings of the equivalent generator protective relaying, but to not include them in this requirement would effectively nullify the stability effort sought by this requirement.
Response: The SDT has modified the Standard to address those relays that have frequency or voltage inputs that would directly trip the unit.		
Constellation Power Generation & Constellation Nuclear	No	The proposed standard addresses all issues identified in the Standard Authorization Request. Coordination of generator and transmission system protection is addressed in PRC-00. As presently constituted this Standard will likely result in the inappropriate enabling and setting of frequency and voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to its stated purpose. This is supported in the comments provided below. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems

Organization	Yes or No	Question 2 Comment
		on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Response: The SDT has modified the Standard to address those relays that have frequency or voltage inputs that would directly trip the unit. The SDT has clarified that generators are not required to install or set the protective relays. The Standard has been modified to address loss of generation consequent to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both.		
Southern Company	No	What the standard addresses is probably what is practical, but the ultimate goal of the SAR is not practical to implement. We question whether the goal of this standard can be truly addressed from a practical standpoint. The scope of the protective equipment covered in the current draft excludes excitation system protection including over excitation, station service under voltage protection, certain nuclear facility protection schemes, boiler controls, turbine controls, each of which may not ride through the frequency and voltage swings. We feel as though the limited approach of specifying F and V relay settings on the generator may be futile in improving the ability to ride through yet on the other hand the inclusion of all of the impacted plant subsystem components would be practically and financially unmanageable. In other words, will any appreciable improvement in system reliability result from the implementation of this standard looking at F and V gen settings only. Settings for generator backup impedance and voltage restrained overcurrent relays may need to be covered too. Their inclusion will provide complete coverage of the generator. There have been instances where these relays have operated in the past. We understand that this will drive the need for dynamic simulations because steady state simulations will not suffice.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions and believes this is practical. An exemption is provided for existing generators that are unable to meet the ride through requirement. The SDT has modified the Standard to address those relays that have frequency or voltage inputs that would directly trip the unit.		
Gainesville Regional Utilities	No	In some areas there is no reason to include generators less than 100 MVA
Response: The SDT believes the Standard should apply to all units that meet the criteria of the compliance registry.		
Basin Electric Power Cooperative	No	Generation under frequency protection is an area I have spend much time on over the last 20 years, and I admit that I hold some strong opinions, but these opinions were arrived at after much study, disturbance analysis, and from being directly involved in actual design of three regional underfrequency load shedding (UFLS) programs. It appears that the generator off-nominal frequency protection limits shown in attachment 1 represent someone's judgment call of what is a reasonable loss of life per event, what the expected minimum frequency might be when load shedding occurs, and so forth. Such judgment calls are subjective, and there is room for interpretation. I feel that generation underfrequency/overfrequency settings of this nature have to be developed on a regional basis as part of a regional underfrequency load shedding program. I am uncomfortable with this showing up in a draft NERC standard without any

Organization	Yes or No	Question 2 Comment
		supporting technical documentation or justification. I agree that unit capabilities have to be considered, but perhaps more important, we have to consider the realities of what we can achieve with UFLS and give ourselves enough generator tripping delay time and relay margin to make the program work. Tradeoff's are involved, and this type of underfrequency analysis is inherently an estimation, so some time delay margin is needed to ensure coordination with load shedding. If generation trips too soon, the island imbalance will increase and it may not be possible to prevent total collapse of the island. Keep in mind that the real off-nominal frequency loss of life exposure is when black start programs try to pick up the pieces after load shedding fails, and premature tripping of generation is what causes load shedding to fail. In addition, hydro systems can operate at much lower frequencies than steam units, and this criteria is not appropriate for hydro systems. In my opinion, UFLS is supposed to be a safety net to cover the unforeseen, and it needs to be designed with that in mind. Ideally, we want it to be as robust as possible. Relay coordination is going to be more robust when based on worst-case performance and not on best case. This helps deal with real world complications imposed by things we have not anticipated or foreseen, or due to "as implemented" programs always being a little different than the ideal stated in the design phase. My most recent involvement with UFLS and generator off-nominal frequency protection coordination came about through the MRO Underfrequency Load Shedding Task Force effort that developed a new coordinated UFLS program for the MRO footprint. I served as chair of this taskforce and did much of the analysis. I do not want PRC-024-1 to establish standards that conflict with the MRO program. Doing so would sacrifice the effectiveness of the load shedding program we came up with. There are a couple of other areas where conflicts occur. This is in regards to how to deal with programs that need to shed more than the minimum amount of load, and in regards to the overfrequency implications. I will discuss the issues in sequence. Although the MRO UFLS Taskforce expects that under "typical conditions" that minimum frequency will be above 58 Hz, (for loss of generation/import of up to 30% of system load in the island), our worst case simulations indicate we could briefly dip below that, and we used our worst case results to set generation protection times and delays. In addition, our "equivalent inertia" modeling approach ignores machine to machine oscillations which might cause frequency at different locations to differ by .2 Hz or so as the system rings down. For this reason, we chose 57.6 Hz as the point where instant tripping is allowed. This is below our worst-case minimum frequency of 57.77 Hz (for a very low inertia, low damping, no governor scenario that is perhaps overly pessimistic). This can also be justified by considering that our design criteria set a target of average system frequency >= 58 Hz, which has to be adjusted by about - .2 Hz for machine to machine oscillations seen in the real system and not in our model, plus about .2 Hz margin to ensure good relay coordination). In order to come up with the MRO generation protection settings we monitored time spent in frequency bands spaced .1 Hz apart and we consider the performance over the full range of coverage (0 to 30 % loss of generation) and considered a wide range of assumptions concerning system based inertia (H system base = MW-sec stored in rotating mass divided by P gen) and damping in addition to a possible range of governor actions. We optimized the program to minimize time spent below 60 Hz while addressing all the other constraints we had to deal with. Once we knew the expected worst case times in each .1 Hz band below 60 Hz for the optimized program, we came up with the stair step type of generation time delay settings that gave a reasonable fit to the expected worst-case time versus frequency information (plus some margin) with the fewest frequency bands. The MRO UFLS effort tried to anticipate as much complication as possible, but we could not cover all of the inherent uncertainty involved. No one could. The main source of uncertainty we could not deal with is how potential overvoltage's may increase load and decrease the effectiveness of the load shedding program. This gave us additional justification for using a "no net governor

Organization	Yes or No	Question 2 Comment
		response" scenario for evaluating coordination between load shedding and generator protection (this voltage uncertainty is not the only reason for using a no governor assumption: basically units that are base loaded cannot respond to underfrequency, power/load controllers may override governor action, combustion turbine thermal limits will quickly override their governor action with power dropping off faster than the frequency decline, wind generation may drop off and would not have a governor anyway, and so forth; the bottom line is that we do not know what level of net governor type of action we can count on, and what little we get may be offset by increases in voltage). To fully understand what we did you will have to refer to the MRO UFLS report on the MRO website. The short version is that we ran 1000's of cases to arrive at our conclusions. What we came up with for generator underfrequency protection minimum time delays is what we need to ensure the load shedding has time to play out to restore frequency and to give some margin to ensure relay coordination. If we tighten up the generation protection time delays and raise the frequency setting for the instant trip point, then there is a narrower range of conditions for which the UFLS program would be expected to work as intended. Our safety net becomes less robust, we make things less secure. On the other hand, the MRO load shedding program is designed to be the first line of protection for the generators as it is designed to force frequency recovery even in the absence of governor action by having small blocks of load shed on delay to kick us back towards 60 Hz when recovery is too slow. Although there is a chance that frequency may be slow to recover as a worst case, most of the time it will recover much faster than the times we used for generation tripping coordination. The expected time spent below 60 Hz sort of takes on the form of a probability density function. This type of information gives a better idea of what units may be exposed to. Therefore, our approach was to coordinate generation off-nominal frequency protection to match the worst case, and then do everything possible to minimize underfrequency exposure to generators when designing the load shedding program. The recommendations of the MRO UFLS report should take precedence over what is being proposed in this document. In MRO, we recognize that the Canadian portion of MRO needs to shed more than 30% of connected load. The MRO UFLS report indicates that any program that needs to shed more than 30% of load will need to relax the MRO generator off nominal frequency time delay settings for generation and accept longer delays and lower minimum frequencies. This is an engineering reality. The Off-Nominal Frequency Capability Curve on Attachment 1 does not give this kind of flexibility. Alternately, some improvement on minimum frequency can be realized by designing a program that oversheds but then the program will be prone to overspeed problems. Programs can also start shedding at higher frequencies to improve the minimum frequency but then that creates other coordination problems with neighboring programs. This standard writing process should not replace engineering judgment. Utilities need flexibility so they can make the necessary compromises after all things are considered. Making adjustments to generation protection is most likely the best approach to ensure coordination with these larger load shedding programs.The diagram from PRC-024-1 may suggest to some folks that over frequency tripping is going to be needed or perhaps even encouraged. I do not know what the intent is, so I will just express my concerns up front. I have serious reservations about applying dedicated relays, of the type used for underfrequency protection, to trip units on overspeed. Extreme caution is needed. That is a good way to ensure total collapse of a power grid. Seriously, this could be catastrophic. Consider that plants already have internal overspeed controls. These are needed to deal with full load rejection. These controls are in addition to the normal governor, and are much more drastic. These emergency overspeed controls are not modeled in stability cases, but they exist, and will take drastic action to slow down units if frequency gets high so I feel confident that the units self protect and take care of themselves. I believe that overspeed protection should be left to these inherent controls, and that we should not put in additional relays to trip generation

Organization	Yes or No	Question 2 Comment
		on overspeed unless this is done carefully and solely for the purpose of restoring load and generation within an island.Plant internal overspeed controls have to limit speed following full load rejection, but they will also react to partial load rejections that we get by islanding. If a plant loses all lines to it (i.e. full load rejection), then go ahead and allow these inherent controls to trip the unit on overspeed or do what ever is needed. NERC does not need a standard for that. The emergency overspeed controls that protect for full load rejection can also activate on an islanding condition where we have too much generation in an island. On steam units these controls kick in between 61 to 62 Hz (it varies with each unit so I have to generalize), so system frequency is unlikely to get much higher than 61.4 Hz to 62 Hz (most that I have seen activate around 61.2 to 61.4 Hz) no matter how large the initial imbalance. Once these controls activate frequency is no longer a measure of the imbalance between load and generation. The action taken to prevent overspeed involves things like closing all the steam valves on thermal units, so it is safe to say we cannot stay in this high frequency condition for too long before random unit trips start to occur due to any number of internal plant problems. Often times one plant dies first and rebalances things for other units. The random nature of what happens next complicates any planned unit tripping actions to correct the imbalance. If dedicated unit tripping on overspeed is to be done, it can only be done on a few selected units and only as a way to hammer the imbalance back to a smaller size that we can deal with. The worst of all worlds would be to apply overspeed tripping to all units like we do for underfrequency. That would ensure any island with an initial excess of generation is going to go black after we dump all the generation. If generation is tripped to correct overspeed in an island, it has to be done in small increments (about 1 to 1.5 % of remaining load) and trip times have to be staggered. This is something that has to be studied on a case-by-case basis.In summary, we do not believe that it is appropriate to be creating a standard like this to specify settings for underfrequency/overfrequency protection for all generation. The technical basis of these limits are not given, and these setting may not coordinate with existing or proposed underfrequency load shedding programs. Aggressive load shedding programs are quite likely to need to accept more time below 60 Hz to coordinate with underfrequency relaying and expected system frequency recovery times. Protection settings of this nature should be developed in conjunction with underfrequency load shedding programs so that appropriate trade offs can be considered. Such coordination is most effective at the regional or subregional basis where a specific load shedding program can be evaluated in detail. We must give sufficient time for load shedding to act even if it means we need to accept some additional potential loss of life to generation for some hypothetical underfrequency event.
Response: The SDT developed the off-nominal frequency capabilities based on turbine manufacturers' capabilities in conjunction with the ability to set relays between the frequency curve and the manufacturers' curves. In addition, the SDT developed the off-nominal frequency curve in coordination with the NERC UFLS Standard Drafting team. The Standard is technology neutral and applies to all generators.		
First Solar	No	The application of the standard to arrays of solar inverters is unclear. While the primary breaker can be set to comply with the standards, when the system voltage is driven to zero during the fault, the inverters will lose their phase lock and begin to shut down.
Response: The Standard includes a provision to document an equipment limitation that would prohibit compliance with Requirements R1 and R2 for		

Organization	Yes or No	Question 2 Comment
existing generators.		
US Bureau of Reclamation	No	Now that the draft standard has been posted, it appears to be a more structured and limited version of existing Standard PRC-001-1 – System Protection Coordination. PRC-001-1 requires the Generator entity to coordinate protection settings with the Transmission entity. The stated Purpose of PRC-024-1 “Ensure that generator frequency and voltage protective relays are set to support transmission system stability during voltage and frequency excursions” should be attainable through PRC-001-1. If PRC-001-1 is not adequate it should be modified rather than adding an additional standard only addressing generator frequency and voltage settings. As such we do not believe there is a clear, reliability based justification for this standard as currently drafted.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
Progress Energy, Inc.	No	The purpose of the standard, to ensure that generators ride through the proposed system transients, will not be accomplished by only looking at generator protective relays. PE is concerned that these same profiles for frequency and voltage (Attachment 1 and 2) could later become applicable to all plant equipment. The generating plants are not designed to ride thru/stay connected for these proposed profiles.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
Hydro-Québec TransEnergie (HQT)	No	The proposed standard addresses all issues identified in the Standard Authorization Request. Coordination of generator and transmission system protection is addressed in PRC-00. As presently constituted this Standard will likely result in the inappropriate enabling and setting of frequency and voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to its stated purpose. This is supported in the comments provided below. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Response: The SDT has modified the Standard to address those relays that have frequency or voltage inputs that would directly trip the unit. The SDT has clarified that generators are not required to install or set the protective relays. The Standard has been modified to address loss of generation consequent to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both.		
Duke Energy	No	Footnote 1 is unclear and too broad. As stated, it includes voltage regulators – which is beyond the scope of this standard. Take voltage regulator out, or specify the volts per hertz protection function only.
Response: The SDT has modified the footnote.		

Organization	Yes or No	Question 2 Comment
New York Independent System Operator	No	As presently constituted this Standard could result in the inappropriate enabling and setting of frequency and Voltage relays with the settings which are permitted, thus reducing system reliability, which is contrary to its stated purpose. This is supported in the comments provided below. It would have been much more important to require that Voltage and frequency relays be applied only when they are required for machine protection, which this Standard does not do. There are significant machine protection issues which are not addressed, such as Volts per Hertz. Loss of generation consequential to problems on auxiliary systems, problems which arise due to low Voltage or low frequency, or a combination of both, is a significant problem, and is not addressed in this Standard.
Response: The SDT has modified the Standard to address those relays that have frequency or voltage inputs that would directly trip the unit. The SDT has clarified that generators are not required to install or set the protective relays. The Standard has been modified to address loss of generation consequent to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both.		
CenterPoint Energy	No	a) CenterPoint Energy does not agree with limiting the application of this standard to the few relays that the SDT has chosen to address (only generator under or over voltage protective relays and volts per hertz relays). In effect, the SDT is allowing possible tripping of generation during off nominal frequency and voltage excursions from several other types of relays and control systems. This may not provide adequate reliability, as loss of significant generation can occur for voltage sags. B) The SDT has not included generator backup over current, impedance, and loss of field relays within the scope of this draft standard. CenterPoint Energy believes these additional relays should also be addressed. CenterPoint Energy believes it is illogical to have a transmission relay loadability standard (PRC-023 Transmission Relay Loadability) based on current and impedance ride-through while exempting generators from comparable requirements. Such an exemption defeats the purpose of the transmission relay loadability requirements by allowing a system event to escalate due to failure of generator relays to ride-through the same types of events envisioned by PRC-023 requirements. One key purpose for PRC-023 is to not interfere with system operators' ability to take remedial action to protect system reliability. C) In addition to including other types of generator relays, the relaying and control for plant auxiliary systems should also be addressed for operation during off nominal frequency and voltage excursions. Again, it is illogical to have a transmission relay loadability requirements based on current and impedance ride-through while exempting a generation plant from comparable requirements. CenterPoint Energy realizes that generating plants have many internal control systems on auxiliary equipment that could be impacted during low voltage events, but exempting such systems from this standard defeats its purpose. CenterPoint Energy also recognizes that failures or incorrect operation of equipment installed for voltage ride-through capability on auxiliary equipment controls, such as UPS devices, will occur. Therefore, CenterPoint Energy recommends the SDT specifically address plant auxiliary equipment ride through. CenterPoint Energy suggests that the requirements be similar to those in NERC standard PRC-004 Analysis and Mitigation of Transmission and Generation Protection System Misoperations. That is, if the plant incorrectly trips during a voltage sag due to auxiliary systems problems, the problem will be investigated and, where necessary, a system-wide

Organization	Yes or No	Question 2 Comment
		corrective action plan will be developed and completed.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
American Wind Energy Association	Yes	A relay setting standard is fine, although the wind industry would also be able to comply with the standard if it were a performance standard.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
AWEA	Yes	PRC-024 should be a performance standard but since that is unlikely to pass I can live with a relay setting standard
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
FirstEnergy	Yes	However, it should clearer in the requirements how mechanical and electrical overspeed protection is coordinated with the UF relay settings. Also, we would appreciate the SDT's view on why the frequency requirement are not being written into the existing PRC-006 (UFLS) standard.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions thus covering all aspects of the generating plant. The SDT has coordinated the development of the UF relay curve with UFLS SDT.		
IRC Standards Review Committee	Yes	We agree that it is a good start.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
Indiana Municipal Power Agency	Yes	A performance standard would be virtually impossible to perform and verify for all the equipment at a plant. The relay approach may not meet the SAR objective for generators to remain on line through voltage and frequency excursions, but this approach is the only practical way that allows standard requirements to be written and enforced.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
American Electric Power	Yes	It is appropriate to limit the scope of this standard to setting of voltage and frequency generator protective relays, but it should be noted that other factors may cause generators to trip as a consequence of voltage or frequency excursions besides voltage or frequency sensing relays. An example is tripping due to complications involving over-excitation protection. Are other factors addressed elsewhere?

Organization	Yes or No	Question 2 Comment
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
Independent Electricity System Operator	Yes	We agree that it is a good start. However, other settings such as those mentioned in the Background Information Section (generator backup over current or impedance, loss of field, etc.) also give rise to tripping of the generator. Consideration should be given to expanding the scope of the SAR to include these settings. The lack of a standard for generator out-of-step protection resulted in adverse effects on the Michigan-Ontario ties during the 2003 blackout.
Response: The SDT has modified the Standard to address those relays that have frequency or voltage inputs that would directly trip the unit, while staying within the scope of the approved SAR.		
Ameren	Yes	Please clearly state that such relays do not have to be added or elements enabled, GO makes the decision what protection to include. R1 and M1, and R2 and M2 should allow for proof that the frequency and/or voltage relays are omitted or set to alarm only, not trip.Please clearly define 'point of interconnection' used in 4.2.2; typically this is where the generating source connects to the switchyard or networked transmission system but these relays are typically at the generator terminals on the low side of the generator step-up transformer.
Response: The SDT has clarified that generators are not required to install or set the protective relays.		
MRO NERC Standards Review Subcommittee	Yes	
Luminant Power	Yes	
Converteam Naval Systems Inc.	Yes	
Consumers Energy Company	Yes	
E.ON U.S.	Yes	
Veolia Environmental Services	Yes	

Organization	Yes or No	Question 2 Comment
Old Dominion Electric Cooperative	Yes	
Southern California Edison Company	Yes	
Brazos Electric Power Cooperative	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
NIPSCo	Yes	
Northeast Utilities	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	
PJM Interconnection	Yes	
Dominion	Yes	
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		

3. PRC-024-1 specifies the limits for generator protective system settings as defined in PRC-024-1 - Attachment 1 and PRC-024-1 - Attachment 2. Are there generating units in your fleet that are not capable of meeting the thresholds in these attachments due to turbine/generator equipment design limitations?

If yes, please estimate the percentage and total MW capacity of your units that cannot meet the requirement.

Estimated total MW capacity of units that cannot meet the requirement:

Summary Consideration:

There was no consensus on this issue.

The issues associated with the majority of the comments received:

1. A wide range (from 0% to 100%) of existing generators may not be able to meet the Standard's requirements based on existing turbine/generator equipment design limitations, auxiliary bus low voltage ride-thru incapability, or manual turbine and automatic reactor protection settings (15 comments)
2. It is not certain, without more study, if equipment limitations will require relay settings in the "no trip" zone (8 comments)
3. It is unclear what limits apply to variable generation (3 comments)
4. The "no trip" curves need clarification (2 comments)

The GV SDT considerations for issues associated with the majority of the comments received are:

1. Requirement R4 has been written to address the inability of existing units to ride-through the voltage and frequency excursions of Attachment 1 and 2. The purpose of this Requirement is to provide the Transmission Planner the ability to more accurately model generating plant performance during system voltage and frequency excursions.
2. The Generator Owner has an opportunity to obtain an exception for those existing units that cannot meet Requirements R1 or R2 in accordance with Requirement R3. R3 has been revised to provide greater clarity on the required documentation of equipment limitation.
3. As written, the BES registry criterea delineates which generating units are in the scope of the standard. The SDT is interested in voltage and frequency rate-of-change concerns and welcomes more technical information on this issue in comments to the next posting.

4. R1, R2, and R3, as well as Attachments 1 and 2, have been revised to provide greater clarity. The table in Attachment 1 showing frequency-time relationship is intended to provide further clarification to the Off Nominal Frequency Capability Curve.

Some other comment issues are:

1. The Jul 2008 UFLS suggested setting state to arrest frequency no lower than 58Hz. Why is Attachment 1 below this value? (2 comments) (Attachment 1 has 57.8 Hz as the no trip threshold.)
2. The basis for the UF curve should be provided (1 comment). (Off nominal OF events have occurred which have exceeded the curve in Attachment 1 with no detrimental effects reported.)
3. Decades of operating experience should be acceptible proof of ride-thru capability (1 comment)
4. Rate of changes in voltage and frequency should be specified on the ride-thru capability requirements (1 comment)

The GV SDT considerations for the other comment issues are:

1. The SDT developed the off nominal frequency curve in coordination with the NERC UFLS Standard Drafting Team. The 57.8 Hz setting for generator underfrequency and 58 Hz for UFLS is to ensure that the UFLS will have a chance to arrest the system frequency decline before reaching the minimum permissible frequency for generators. The intent of the curves is to ensure that the generators do not trip when the frequency is within the area bounded by the high and low frequency curves. When the frequency excursion reaches outside the high or low curve, the generator is allowed to trip.
2. The SDT developed the off nominal frequency capabilities based on turbine manufacturers' capabilities in conjunction with the ability to set relays between the frequency curve and the manufacturers' curves.
3. The Generator Owner has an opportunity to obtain exception for those existing units that cannot meet Requirements R1 or R2 in accordance with Requirement R3. R3 has been revised to provide greater clarity on the required documentation of equipment limitation.
4. The SDT is interested in voltage and frequency rate-of-change concerns and welcomes more technical information on this issue in comments to the next posting.

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
Northeast Utilities		Information not available at this time.	Information not available at this time.

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
Response: Thank you for your comments.			
Independent Electricity System Operator		We are unable to comment on how many generating units in the fleet that are not capable of meeting the threshold in the Attachments since we are not a Generator Owner. However, we are unclear on the basis of the 57.8 Hz setting stipulated in R1.3 as it is not consistent with the proposed UFLS characteristics (posted in July of 2008) in which it indicates that frequency should be arrested at no less than 58.0 Hz. Further, the basis for the very restrictive over-frequency curve proposed in attachment #1 is not obvious. The over-frequency standard proposed in PRC-024 was exceeded during the blackout of 2003 for Ontario generation that was connected radically into New York. No adverse effects attributed to this over frequency event have been reported to the IESO.	
Response: The SDT developed the off nominal frequency capabilities based on turbine manufacturers' capabilities in conjunction with the ability to set relays between the frequency curve and the manufacturers' curves. In addition, the SDT developed the off nominal frequency curve in coordination with the NERC UFLS Standard Drafting Team. The 57.8 Hz setting for generator underfrequency and 58 Hz for UFLS is to ensure that the UFLS will have a chance to arrest the system frequency decline before reaching the minimum permissible frequency for generators. The intent of the curves is to ensure that the generators do not trip when the frequency is within the area bounded by the high and low frequency curves. When the frequency excursion reaches outside the high or low curve, the generator is allowed to trip.			
MRO NERC Standards Review Subcommittee	No	The MRO does not own any generation.	
Response: Thank you for your comments.			
FirstEnergy	No	A possible concern would be the effect on auxiliary system equipment and reliability at voltages below 90%.	
Response: Thank you for your comments.			

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
IRC Standards Review Committee	No	We are unable to comment on how many generating units in the fleet that are not capable of meeting the threshold in the Attachments since we are not a Generator Owner. However, we are unclear on the basis of the 57.8 Hz setting stipulated in R1.3 as it is not consistent with the proposed UFLS characteristics (posted in July of 2008) in which it indicates that frequency should be arrested at no less than 58.0 Hz.We also think the question is a bit misleading and may not result in providing the SDT any grounded suggestions or concurrence on the appropriate frequency levels that the SDT may already have in mind. The question as written suggests that the SDT is trying to canvass the industry through this commenting process. This is a way to obtain feedback, but it does not provide the rationale of the proposed levels. We suggest that the SDT research the limitations of the machines that are connected to the BPS (perhaps by a survey or a NERC data request) to better support the proposed frequency limit, then ask for concurrence or alternative suggestions.	
Response: Thank you for your comments. The SDT developed the off nominal frequency capabilities based on turbine manufacturers' capabilities in conjunction with the ability to set relays between the frequency curve and the manufacturers' curves. In addition, the SDT developed the off nominal frequency curve in coordination with the NERC UFLS Standard Drafting team. The 57.8 Hz setting for generator underfrequency and 58 Hz for UFLS is to ensure that the UFLS will have a chance to arrest the system frequency decline before reaching the minimum permissible frequency for generators.			
Consumers Energy Company	No	Consumers Energy doesn't have generating units that cannot meet the thresholds. However, we would like to offer the following comments:The Standards Drafting Team should be congratulated for the excellent curves in Attachment 1. A review of our fleet which contains units of several vintages, manufactured by General Electric, Westinghouse, Siemens, and Allis-Chalmers, shows that turbine-generators from all of these manufacturers comply with these curves. To assist Generator Owners and Compliance Auditors, the SDT should furnish mathematical formulae for the "slanted lines" in the curves. Should a	

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
		Generator Owner elect to set an underfrequency relay at 120 seconds and 59.1 Hz, there might be uncertainty or disagreement about compliance, depending upon how the interpolation of the graph is viewed. Interpolation from a semi-log plot is often not easy. This uncertainty can and should be eliminated by including the two formulae in Attachment 1.	
Response: Thank you for your comments. The table in Attachment 1 showing frequency-time relationship is intended to provide further clarification to the Off Nominal Frequency Capability Curve.			
Old Dominion Electric Cooperative	No	I am not 100% sure this is the case, but I am fairly confident all our units do meet these thresholds.	
Response: Thank you for your comments.			
Basin Electric Power Cooperative	No	It is unclear what limits apply to wind generation, but we believe our conventional generation can easily accommodate the settings defined by Attachment 1, even though we feel that such off-nominal protection settings should not be established in this standard and that such coordination should occur at the regional level were UFLS program details are worked out. I would like to offer some observations based on real life experience. Our experience is that some folks have a good technical understanding of generation capabilities and others do not. In many instances, folks do not know what actual capabilities are, and if the proposed settings conflict with existing settings then they will initially report that they cannot accommodate the recommendations (the status quo carries a lot of weight even when no one can find the original justification for existing settings). Generally, all the parties have to get together and work through things to create a higher level of awareness of the issues so we can eliminate misconceptions. The new non-utility generation owners do not have the same load serving obligations as traditional utilities and this gives them different incentives for	

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
		how they want to set generation protection. In many instances, they want to trip too early, to the detriment of the grid.	
Response: Thank you for your comments. Regional Entities may set requirements more stringent than the NERC Standard to address regional requirements.			
Entergy Fossil Operations	No		
Luminant Power	No		
E.ON U.S.	No		
AWEA	No		
Gainesville Regional Utilities	No		
American Wind Energy Association	No		
Veolia Environmental Services	No		
Lakeland Electric	No		
Manitoba Hydro	No		
American Electric Power	No		
US Bureau of Reclamation	No		
American Transmission	No	ATC does not own any generation	

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
Company			
Response: Thank you for your comments.			
Progress Energy, Inc.	Yes	100% of Progress Energy nuclear units will not stay connected per the proposed Attachment 1 and 2 due to auxliary equipment protection.70-80% of the combustion turbine units would trip during the frequency excursions proposed by NERC.To make sure that generation "ride through" is coordinated with conditions that could damage all types of generation facilities, Progress Energy recommends that the SDT consult with turbine manfacturers to develop the frequency profile. Frequency limitations are typically driven by turbine manfacture design. We also need to the mindful of the total cummulative off-frquency excursions limits laid down by the turbine manufacturers.For example, most large steam turbine vendors prohibit turbine operation below 58 hz in order to prevent the probable occurrence of turbine blade resonance (turbine blade failure). Our nuclear plant operators will immediately manually trip the turbines at 58 hz to prevent equipment damage. For combustion turbines under frequency limitations exist below 59 Hz while the maximum operating duration at 59.5 Hz is limited to 60 seconds. Of our five nuclear plants, all five would not be capable of riding through either the proposed frequency or voltage transitents due to manual turbine and automatic reactor protection settings. These settings are not generator protective relays but they will result in a complete loss of generation. Two Progress Energy nuclear plants will trip on reactor coolant pump undervoltage below 80% pu at 0.75 seconds and one will trip on underfrequency below 58.2 hz at 0.2 seconds.	Approximately 3,500 MW of nuclear generation for SERC and 900 MW for FRCC. Approximately 3500 MW CT generation in SERC and 5000 MW CT generation in FRCC.
Response: Thank you for your comments. The SDT developed the off nominal frequency capabilities based on turbine manufacturers' capabilities in conjunction with the ability to set relays between the frequency curve and the manufacturers' curves. In addition, the SDT developed the off nominal frequency curve in coordination with the NERC UFLS Standard Drafting Team.			

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
NIPSCo	Yes	4.7 % estimated percentage of units that can't meet thresholds due to design limitations:	155 Estimated total MW capacity of units that cannot meet the requirement.
Response: Thank you for your comments.			
Hydro-Québec TransEnergie (HQT)	Yes	A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.	A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
Response: Thank you for your comments.			
Northeast Power Coordinating Council	Yes	A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.	A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.
Response: Thank you for your comments.			
Kansas City Power & Light	Yes	There are a number of generating units that currently have relay settings outside the proposed underfrequency and overfrequency relay settings. It is not known at this time if it is possible to adjust the settings within the proposed relay settings.50%	1900 MW
Response: Thank you for your comments.			
Duke Energy	Yes	15% of system capacity	Approximately 4000 MW
Response: Thank you for your comments.			
New York Independent System Operator	Yes	A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.	A relatively small percentage of units do not meet this requirement but it is not known which of these cases are due to actual machine design limitations.

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
Response: Thank you for your comments.			
Constellation Power Generation & Constellation Nuclear	Yes	A number of our units do not meet this requirement but it is not known which of these cases are, due to actual machine design limitations.	
Response: Thank you for your comments.			
Ameren	Yes	We have not yet performed a detailed review wrt proposed limits, but expect there will be some that are not capable of meeting these stated thresholds. It can be hard to get capability data and warranties have expired, for older units or those purchased from other owners. The PRC-024-1 curves should not become a de facto requirement. If decades of operating experience have proven satisfactory from both a BES and generator equipment life persperctive, this should be accepted as evidence as well. Generic guidance, such as past ANSI/IEEE standards, recommended practices, and guides should be allowed for older units exception evidence as well. Clearly state that field testing is not required.	
Response: Thank you for your comments. The Generator Owner has an opportunity to obtain an exception for those existing units that cannot meet Requirements R1 or R2 in accordance with Requirement R3. R3 has been revised to provide greater clarity on the required documentation of equipment limitation.			
Southern California Edison Company	Yes	Uncertain, as curves and tables in attachments need additional clarification.	Uncertain, as curves and tables in attachments need additional clarification.
Response: Thank you for your comments. R1, R2, and R3, as well as Attachments 1 and 2, have been revised to provide greater clarity.			
Southern Company	Yes	Some are, some are not. Some we can prove, some we don't know and can't find out. With no experts to evaluate turbine under/over frequency in our company and turbine manufacturers	40,000MW voltage, Unknown frequency

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
		either out of business or unwilling to provide turbine limits, is there any possible exception allowed for settings inside the no trip zone? Also, for existing turbines, we believe that the turbine blade conditions would have to be evaluated to make a judgement on how to shift the withstand. How can we be sure that we are not stressing our turbine if we set our devices outside of the curve in the standard? Can question 3 be addressed quantitatively? Instead of "100% on voltage", it should be "0%".Auxiliary systems are not included in the standards scope as drafted.100% on voltage (can't prove - auxilliary system) Unknown on frequency	
Response: Thank you for your comments. The Generator Owner has an opportunity to obtain exception for those existing units that cannot meet Requirements R1 or R2 in accordance with Requirement R3.			
First Solar	Yes	The response, and therefore compliance with this proposed Standard, are not clear. The standard does not seem to contemplate static power generators that would be part of renewable energy systems like solar PV. As part of the requirement there should be specificity on a number of points. For example as written it does not clearly define what the generator does during the out of frequency/voltage conditions. Presumably the inverters would not be required to drive current into the fault and thereby increase fault duties. Furthermore, once the fault is cleared, it does not define the speed/rate at which power is ramped up from the generator. This rate could be hard to achieve with a static converter. Finally, the standard does not define the rate of change of frequency or voltage. Typically devices are more sensitive to high rate changes. All of these items need more detail and specificity to determine how new forms of generation can meet these requirements.	
Response: The SDT thanks you for your comments. The standard does apply to variable energy resource facilities such as solar PV. The standard does not set requirements for generator output during a fault. Conventional synchronous generators will supply fault current so that protective relaying can			

Organization	Yes or No	Question 3 Estimated percentage of units that can't meet thresholds due to design limitations:	Question 3 Estimated total MW capacity of units that cannot meet the requirement:
detect the fault expeditiously. A performance requirement (R6) has been added for new generation (designed, built, and connected to the grid) after the Standard becomes effective, but does not specify a post-fault output for a facility. The SDT has added a limit to the rate of change of frequency that the Generator Owner is expected to ride through.			

4. The curve in PRC-024-1 — Attachment 2 was based upon analysis performed of simulated system disturbances. System voltage traces representative of several hundred disturbances were co-plotted on a voltage versus time graph. The voltage duration curve in this attachment is derived from these voltage traces. A margin was then applied to the voltage duration curve to account for unanticipated system conditions. The 9 cycle fault clearing time required by the FERC 661-A Order is incorporated into this curve. Given this background on the development of PRC-024-1 — Attachment 2, do you agree with the parameters of the curve? If not, please explain in the comment area.

Summary Consideration:

- A majority of respondents indicated support that simulations should be verified.
- Some commenters questioned the general applicability:
  - o Wind generator performance requirements should not be imposed on synchronous generator relay settings
  - o Curves should be based on generator capabilities, not on expected system performance
  - o Generators should not trip on under voltage but should only alarm
  - o Concern that the curves could be extended to other plant equipment
- Still other commenters questioned specific values:
  - o Delayed clearing may require 30 cycles at zero voltage, 9 cycles is inadequate
  - o The curve should go to at least 10 seconds at 0.9pu, not 4. Also 2 seconds at 0.45pu, and 3 seconds at 0.75pu
  - o Phase to ground faults will result in higher voltages on the un-faulted phases
  - o It is not clear if the curves are for phase to neutral voltages, phase to phase voltages, or positive sequence voltages
- Another minority comment was that relays are at the machine terminals not at the POI so the curves should be applied at the generator terminals

The GV SDT has determined that the curves in Attachment 2 are reasonable. Only minor modifications were contemplated, such as the addition of new text in the notes section.

Organization	Yes or No	Question 4 Comment
NERC System Protection and	No	FERC 661-A is a wind generator facility ride-through performance criterion, not a synchronous generator relay setting requirement. They cannot be compared as being equivalent. A synchronous generator undervoltage capability will be quite

Organization	Yes or No	Question 4 Comment
Control Subcommittee (SPCS)		different from an entire wind facility undervoltage ride-through capability. The 9 cycle zero voltage interval is inadequate. The 9 cycle setting would cover for most normally cleared faults but generators must also remain on line through faults with delayed clearing due to breaker failure as required in the NERC TPL Standards. The time interval for such clearing is more typically 12 to 15 cycles. This time delay can increase to 0.5 seconds if high speed protection is out of service, for example a single relay communication channel, at the time of a fault and the fault is then cleared in zone 2 time. SPCS believes that R.R.1 is worded in a confusing way. It implies that you had to trip in 9 cycles or less - rather than not trip for a minimum of 9 cycles- albeit we want to wait longer than that. SPCS respectfully questions whether it is conceptually possible to properly state these criteria as a single curve. It is more appropriate to have separate requirements for wind generation and other generators. Additionally, they should differ related to points of interconnections (a contractual arrangement), and refer to the high-side of the GSU for all other generation. This would lend consistency and avoid unnecessary confusion. There are a number of important issues that arise with current approach, including: In general, generator protection should not trip generators on UV, but should alarm, as stated in IEEE C37.102. Please also see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is more appropriate to call operator attention to a malfunction. The existence of a curve such as this in a NERC Standard will lead to generator owners enabling UV relays to trip and setting them per the curve, which is a serious danger to system reliability. For some specific situations such as unmanned hydro units, tripping on time-UV may be considered. The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate for other generators. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines. The Voltages presented are at the point of interconnection and are not directly translatable to machine relay voltage settings. Machine Volts/Hertz curves are a significant issue and are not addressed. The UV performance of plant auxiliaries is a significant issue, and is not addressed. The standard should be very clear to discourage plant owners from setting under- and over- voltage relays if they don't already have them, or need them for very specific situations. SPCS also is concerned because it appears the SDT has considered only the positive sequence voltage in developing the curves in Attachment 2. Overvoltage relays measure individual phase-to-ground or phase-to-phase quantities and SPCS expect that generator owners will apply these curves based on the quantities measured by the relays in developing relay settings. As such, the curves must be based on the quantities that are measured by protective relays and the quantities must be clearly stated. To highlight our concern, consider that for a line-to-ground fault at the point of interconnection on an effectively grounded system the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault. Under such conditions generators with overvoltage relays set per the curve may trip at 120% voltage prior to clearing the fault from the transmission system. Under these conditions tripping is not required for generator protection and may have a detrimental impact on system reliability, yet it is permissible per the proposed curve. There is guidance in the industry and C37.102 to provide dielectric (insulation) protection for extremely high voltages, however 120 % voltage is overprotecting the generator. For Generator protection, the first line of defense is generator surge arrestors but some units may also use a high set overvoltage protection as well. This voltage is a much higher level then 120% shown in the curve (i.e. 150% of rated voltage). Voltage relays applied to the system side of the generator step-up transformer should be configured and set in such a way that they do trip the generator for higher voltages on unfaulted phases for phase-to- ground faults. As you may know generator windings are sometimes tested with high potential: New machines can be tested as high as twice (200%) rated line-to-line voltage plus 1000 Volts (Commissioning

Organization	Yes or No	Question 4 Comment
		High Pot) for one minute. Older Machines that are in service for significant time can be tested at 125% to 150% of rated line-to-line voltage (Maintenance High Pot) for one minute. There are some industry differences of opinion on this topic of course but 120% instantaneously is too low.Voltage settings are based on type of insulation material (Class F is in common present days) and its thickness. A curve would need to be developed that takes insulation thickness into account. USBR's practice is to use manufacture designed 105% continuous. Then, 59 is set a 110% of 105% (continuous use) for time coordination (TOV) and 130% of 105% of phase-to-ground voltage for instantaneous (IOV).
Response: Thank you for your detailed response to this question. Based on industry input a Requirement has been added to require generators designed and built after the Standard goes into effect to ride through voltage and frequency excursions. The Standard is technology neutral and applies to all generators. The SDT has clarified that generators are not required to install or set the relays to trip. The Standard has been modified to address loss of generation consequent to problems on auxiliary systems, problems which arise due to low voltage or low frequency, or a combination of both. The intent of the Standard is to provide a definition of the no trip boundary for generator relay operation (existing plants) or generating facility performance (new plants). If the generator can remain on line during this boundary, no relay changes or modifications are required. The boundary defines generator relay settings for normally cleared three-phase fault on the transmission system and does not address transmission relay failures that would result in delayed clearing. Delayed clearing with the POI voltage at zero presents serious out-of-step issues for generators. The SDT recognizes the IEEE C37.102 requirement that generator protection should not trip on undervoltage, but should alarm. The proposed PRC-24-1 Standard does not require tripping, but rather defines a boundary when generators that are equipped with high and low voltage relays should not trip generators. Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings.		
Northeast Power Coordinating Council	No	Both bullets should be checked above (form will not accept).The curves should be revised based on generator capabilities and design requirements rather than the expected system response for simulated disturbances. Although the simulation results and tools used to develop the curves have not been provided it appears that the proposed curves are based on transient stability simulations. The transient stability program includes only the positive sequence component of system voltage and neglects phenomena that do not result in significant shaft torques. By contrast, protective relays measure individual phase or phase-to-phase quantities or in some cases specific sequence quantities. As proposed the curves may be interpreted differently in relay applications to the detriment of bulk electric system reliability and customer service. Since the curves will be used to set protective relays they should be based on the quantities that are measured by protective relays and the quantities should be clearly stated. We have provided examples of how the curves could be misinterpreted or misapplied if the curves are not constructed in terms of measured relay quantities and settings specific to the point of measurement: Based on the proposed curve an overvoltage relay can be set at 120% with no intentional time delay. If this relay measures phase-to-ground voltage at the Point of Interconnection (POI) then for a close-in line-to-ground fault the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault (effectively grounded system), resulting in undesired generator tripping prior to clearing the fault from the transmission system. Protection against overvoltages that are shorter in duration than the operating time of circuit breaker is provided by surge arresters on the high-voltage terminals of the transformer and by surge protectors on the terminals of the generator. The curve implies that for a voltage of more than 120% that the generator can trip instantaneously (without intentional time

Organization	Yes or No	Question 4 Comment
		delay). We suggest that instantaneous trips at any voltage level are neither required nor effective for generator protection. The overvoltage curve should approach zero time asymptotically or alternatively 250% for 20ms, 135% for 300ms, 120% for 20 seconds, 110% continuously. Alternatively the curve should be based on generator capability rather than FERC 661A which is applicable to wind generators with very limited capability. In the undervoltage region the 9 cycle zero voltage has been carried over from FERC 661-A which is to facilitate wind integration. The 9 cycle zero voltage ride-thru, although less than prior utility designs, may be sufficient. We again recommend that SDT translate the intended positive sequence values to phase quantities measured by the relay to avoid misapplication. A single-line-to-ground fault will result in a positive sequence voltage of approximately 0.5-0.7pu but the voltages on individual phases or between phases may be quite different. The curve appears adequate from a positive sequence perspective but may not be interpreted as intended. In the undervoltage region we recommend that 85% be applied from 3 seconds to 15 seconds to ensure that generators stay connected longer than load and to permit time for automatic reactive element switching. There is no reason to trip this fast in this regionBased on the proposed curves we are concerned that the SDT has considered only the system response to typical design contingencies and only the positive sequence voltage from transient stability simulations. Although we have suggested alternate values the final values will depend on how the curve is defined, the form of measurement and relay application. As proposed we believe the curves leave too much for misinterpretation and misapplication.We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following:> In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a malfunction.> The existence of a curve such as this in a NERC Standard will lead to generators enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability.> For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate.> The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines.> The minimum voltage for 9 cycles does not allow enough time to allow for breaker failure protection operation. 13 -15 cycles would be appropriate.> The voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings.> Machine Volts per Hertz curves are a significant issue and are not addressed.> The UV performance of plant auxiliaries is a significant issue, and is not addressed.> We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard.

Response: Thank you for your detailed response to the question. Development of the voltage ride-through curve started by reviewing the needs of the transmission system and then comparing them to known technical papers and standards. The positive sequence models of the power system that were utilized in the performance analysis did include detailed machine representation accepted by IEEE which calculated shaft torques and other machine parameters. The SDT recognizes the IEEE C37.102 requirement that generator protection should not trip on undervoltage, but should alarm. The proposed PRC-24-1 Standard does not require tripping, but rather defines a boundary when generators that are equipped with high and low voltage relays should not trip generators. The SDT has clarified that generators are not required to install or set the relays to trip. Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings. The boundary defines generator relay settings for normally cleared three-phase fault on the transmission system and does not address transmission relay failure that would

Organization	Yes or No	Question 4 Comment
result in delayed clearing.		
Kansas City Power & Light	No	R2 specifies that the generator may not operate on V/Hz evaluated at nominal frequency. Some generators have specific requirements to trip on V/Hz at 110%. This is in conflict with the upper boundry point of Attachment 2 for times greater than 1 second. We recommend to change this requirement so that it does not apply to V/Hz settings. It is not practical to set generator protective relays fed from generator potential transformers to meet the voltage requirement at the point of interconnect to the BES. We recommend that the voltage chart requirement be applicable to the voltage measured by the generator protective relays, not the voltage at the point of interconnect to the BES.
Response: Thank you for providing a response to this question. Attachment 2 defines voltage durations at the generating facility substation (POI). For a POI voltage of 1.1pu the voltage at the generator terminals will be lower due to voltage regulation and the impedance of the step-up transformer. The Standard is concerned with generator response to excursions on the transmission system, so the voltage profile in Attachment 2 must be defined at the transmission voltage (POI) level. The equivalent profile at the generator terminals depends on the characteristics of the equipment at each facility, so the Generator Owner would have to determine how it affects his specific equipment.		
Constellation Power Generation & Constellation Nuclear	No	The curves should be revised based on generator capabilities and design requirements rather than the expected system response for simulated disturbances. Although the simulation results and tools used to develop the curves have not been provided it appears that the proposed curves are based on transient stability simulations. The transient stability program includes only the positive sequence component of system voltage and neglects phenomena that do not result in significant shaft torques. By contrast, protective relays measure individual phase or phase-to-phase quantities or in some cases specific sequence quantities. As proposed the curves may be interpreted differently in relay applications to the detriment of bulk electric system reliability and customer service. Since the curves will be used to set protective relays they should be based on the quantities that are measured by protective relays and the quantities should be clearly stated. We have provided examples of how the curves could be misinterpreted or misapplied if the curves are not constructed in terms of measured relay quantities and settings specific to the point of measurement: Based on the proposed curve an overvoltage relay can be set at 120% with no intentional time delay. If this relay measures phase-to-ground voltage at the Point of Interconnection (POI) then for a close-in line-to-ground fault the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault (effectively grounded system), resulting in undesired generator tripping prior to clearing the fault from the transmission system. Protection against overvoltages that are shorter in duration than the operating time of circuit breaker is provided by surge arresters on the high-voltage terminals of the transformer and by surge protectors on the terminals of the generator. The curve implies that for a voltage of more than 120% that the generator can trip instantaneously (without intentional time delay). We suggest that instantaneous trips at any voltage level are neither required nor effective for generator protection. The overvoltage curve should approach zero time asymptotically or alternatively 250% for 20ms, 135% for 300ms, 120% for 20 seconds, 110% continuously. Alternatively the curve should be based on generator capability rather than FERC 661A which is applicable to wind generators with very limited capability. In the undervoltage region the 9 cycle zero voltage has been carried over from FERC 661-A which is to facilitate wind integration. The 9 cycle zero voltage ride-thru, although less than prior utility designs, may be sufficient. We again

Organization	Yes or No	Question 4 Comment
		recommend that SDT translate the intended positive sequence values to phase quantities measured by the relay to avoid misapplication. A single-line-to-ground fault will result in a positive sequence voltage of approximately 0.5-0.7pu but the voltages on individual phases or between phases may be quite different. The curve appears adequate from a positive sequence perspective but may not be interpreted as intended. In the undervoltage region we recommend that 85% be applied from 3 seconds to 15 seconds to ensure that generators stay connected longer than load and to permit time for automatic reactive element switching. There is no reason to trip this fast in this regionBased on the proposed curves we are concerned that the SDT has considered only the system response to typical design contingencies and only the positive sequence voltage from transient stability simulations. Although we have suggested alternate values the final values will depend on how the curve is defined, the form of measurement and relay application. As proposed we believe the curves leave too much for misinterpretation and misapplication.We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following:* In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a malfunction.* The existence of a curve such as this in a NERC Standard will lead to generators enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability.* For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate.* The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines.* The minimum voltage for 9 cycles does not allow enough time to allow for breaker failure protection operation. 13 -15 cycles would be appropriate.* The voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings.* Machine Volts per Hertz curves are a significant issue and are not addressed.* The UV performance of plant auxiliaries is a significant issue, and is not addressed.* We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard.

Response: Thank you for your detailed response to the question. Development of the voltage ride-through curve started by reviewing the needs of the transmission system and then comparing them to known technical papers and standards. The positive sequence models of the power system that were utilized in the performance analysis did include detailed machine representation accepted by IEEE which calculated shaft torques and other machine parameters. The SDT recognizes the IEEE C37.102 requirement that generator protection should not trip on undervoltage, but should alarm. The proposed PRC-24-1 Standard does not require tripping, but rather defines a boundary when generators that are equipped with high and low voltage relays should not trip generators. The SDT has clarified that generators are not required to install or set the relays to trip. Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings. The boundary defines generator relay settings for normally cleared three-phase fault on the transmission system and does not address transmission relay failure that would result in delayed clearing. The Standard is concerned with generator response to excursions on the transmission system, so the voltage profile in Attachment 2 is defined at the transmission voltage (or POI) level. The equivalent profile at the generator terminals depends on the characteristics of the equipment at each facility, so the Generator Owner would have to determine how it affects his equipment and evaluate accordingly. Machine Volts per Hertz capabilities were reviewed by the SDT. The upper boundary of the voltage duration curve in Attachment 2 is designed to accommodate those limits.

Organization	Yes or No	Question 4 Comment
Southern Company	No	Controversy of Voltage cumulative nature, not showing the 95%-100% generator terminal voltage, difference between the curve being on the tranmission side of the GSU and the generator relay being on the generator side of the GSU. The generator terminal voltage shown at 95%-105% listed in R2.1. We are concerned that future auditors will interpret this limit as being the coordination limit. The voltage curve of Attachment 2 is stated for system voltage; however as mentioned in the conference call, the volts per hertz protection was specifically referenced and used to support setting criteria. We have a problem with this approach since the V/HZ relay is looking at the generator voltage and the curve is shown for the system voltage. How do we demonstrate coordination since the two are on different basis which cannot accurately be resolved via steady state techniques?The wording used in section R2.2.1 is confusing. The words should be changed to "For three-phase transmission system zone 1 faults with Normal Clearing, generator relaying shall be set longer than the expected fault clearing time, but does not have to be set for greater than nine cycles."
Response: Thank you for your detailed response to the question. The Attachment 2 voltage ride-through diagram is referenced to the point of interconnection to the BES; therefore, addressing the generator terminal voltage on this diagram would add confusion. Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings. The reference document addressed interactions between the synchronous generator Volts/Hertz curves and the Attachment 2 curve. The Attachment 2 curve is intended to fit within the Volts/Hertz curve requirements. The voltage profile at the generator terminals depends on the characteristics of the equipment at each facility and can be determined either by load flow for steady state conditions or dynamically. The Generator Owner would have to determine how it affects his equipment and evaluate accordingly. The SDT has clarified the R2.1 (now R2.1.1. in the revised standard) Standard language.		
Converteam Naval Systems Inc.	No	please see my further comments on this.
Response: Thank you for your comment.		
Gainesville Regional Utilities	No	I am concerned that Generator Operators even understand what is written above
Response: Thank you for providing a response to this question. The Standard is intended to be written such that generator operators will understand the requirements. We welcome any recommendations would help to clarify the document.		
Southern California Edison Company	No	Additional information is need for clarity on the curve and table in the attachment.
Response: Thank you or providing a response to the question. We welcome any recommendations that would help to clarify the document.		

Organization	Yes or No	Question 4 Comment
Basin Electric Power Cooperative	No	This may be appropriate but I have not seen the supporting technical report so I cannot say that I agree.
Response: Thank you or providing a response to the question. Supporting documents are available on the NERC website.		
Progress Energy, Inc.	No	PE is concerend that the proposed profile for voltage (Attachment 2) could later become applicable to all plant equipment. The generating plants are not designed to ride thru/stay connected for this proposed profile. 100% of our nuclear units will trip if subjected to the proposed voltage transient test. The trips would be due to reactor coolant pump undervoltage, reactor coolant pump power monitoring protection, and reactor protection system power supply undervoltage exceeding their respective time delays during the voltage excursion. Each nuclear plant has slightly different trips based on the reactor design and vintage.
Response: Thank you or providing a response to the question. For existing generators, the proposed PRC-24-1 Standard defines requirements for the setting of generator protective relays. The Standard does not require a redesign of the auxiliary systems for existing generators. For generating facilities that are designed and built after this Standard goes into effect, a new performance requirement has been added.		
Hydro-Québec TransEnergie (HQT)	No	The curves should be revised based on generator capabilities and design requirements rather than the expected system response for simulated disturbances. Although the simulation results and tools used to develop the curves have not been provided it appears that the proposed curves are based on transient stability simulations. The transient stability program includes only the positive sequence component of system voltage and neglects phenomena that do not result in significant shaft torques. By contrast, protective relays measure individual phase or phase-to-phase quantities or in some cases specific sequence quantities. As proposed the curves may be interpreted differently in relay applications to the detriment of bulk electric system reliability and customer service. Since the curves will be used to set protective relays they should be based on the quantities that are measured by protective relays and the quantities should be clearly stated. We have provided examples of how the curves could be misinterpreted or misapplied if the curves are not constructed in terms of measured relay quantities and settings specific to the point of measurement: Based on the proposed curve an overvoltage relay can be set at 120% with no intentional time delay. If this relay measures phase-to-ground voltage at the Point of Interconnection (POI) then for a close-in line-to-ground fault the unfaulted phases may have fundamental frequency voltages of 125% or more for the duration of the fault (effectively grounded system), resulting in undesired generator tripping prior to clearing the fault from the transmission system. Protection against overvoltages that are shorter in duration than the operating time of circuit breaker is provided by surge arresters on the high-voltage terminals of the transformer and by surge protectors on the terminals of the generator. The curve implies that for a voltage of more than 120% that the generator can trip instantaneously (without intentional time delay). We suggest that instantaneous trips at any voltage level are neither required nor effective for generator protection. The overvoltage curve should approach zero time asymptotically or alternatively 250% for 20ms, 135% for 300ms, 120% for 20 seconds, 110% continuously. Alternatively the curve should be based on generator capability rather than FERC 661A which is applicable to wind generators with very limited capability.

Organization	Yes or No	Question 4 Comment
		In the undervoltage region the 9 cycle zero voltage has been carried over from FERC 661-A which is to facilitate wind integration. The 9 cycle zero voltage ride-thru, although less than prior utility designs, may be sufficient. We again recommend that SDT translate the intended positive sequence values to phase quantities measured by the relay to avoid misapplication. A single-line-to-ground fault will result in a positive sequence voltage of approximately 0.5-0.7pu but the voltages on individual phases or between phases may be quite different. The curve appears adequate from a positive sequence perspective but may not be interpreted as intended. In the undervoltage region we recommend that 85% be applied from 3 seconds to 15 seconds to ensure that generators stay connected longer than load and to permit time for automatic reactive element switching. There is no reason to trip this fast in this regionBased on the proposed curves we are concerned that the SDT has considered only the system response to typical design contingencies and only the positive sequence voltage from transient stability simulations. Although we have suggested alternate values the final values will depend on how the curve is defined, the form of measurement and relay application. As proposed we believe the curves leave too much for misinterpretation and misapplication.We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following:> In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a malfunction.> The existence of a curve such as this in a NERC Standard will lead to generators enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability.> For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate.> The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines.> The minimum voltage for 9 cycles does not allow enough time to allow for breaker failure protection operation. 13 -15 cycles would be appropriate.> The voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings.> Machine Volts per Hertz curves are a significant issue and are not addressed.> The UV performance of plant auxiliaries is a significant issue, and is not addressed.> We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard.

Response: Thank you for your detailed response to the question. Development of the voltage ride-through curve started by reviewing the needs of the transmission system and then comparing them to known technical papers and standards. The positive sequence models of the power system that were utilized in the performance analysis did include detailed machine representation accepted by IEEE which calculated shaft torques and other machine parameters. The SDT recognizes the IEEE C37.102 requirement that generator protection should not trip on undervoltage, but should alarm. The proposed PRC-24-1 Standard does not require tripping, but rather defines a boundary when generators that are equipped with high and low voltage relays should not trip generators. The SDT has clarified that generators are not required to install or set the relays to trip. Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings. The boundary defines generator relay settings for normally cleared three-phase fault on the transmission system and does not address transmission relay failure that would result in delayed clearing. The Attachment 2 curve is intended to fit within the Volts/Hertz curve requirements. The voltage profile at the generator terminals depends on the characteristics of the equipment at each facility and can be determined either by load flow for steady state conditions or dynamically. The Generator Owner would have to determine how it affects his equipment and evaluate accordingly.

Organization	Yes or No	Question 4 Comment
New York Independent System Operator	No	We respectfully question whether it is conceptually possible to properly state this criteria as a single curve. There are a number of important issues that arise with this approach, including the following:> In general generators should not trip on UV, but should alarm. Please see latest C50.12 and C50.13. UV is generally a thermal consideration and an alarm is appropriate to call operator attention to a situation or malfunction which results in low voltage.> The existence of a curve such as this in a NERC Standard will lead to some generator owners enabling UV and setting per some part of the curve, which could be a serious hazard to system reliability.> For some specific situations such as unmanned hydro units, tripping on time-UV is appropriate.> The idea of a ride-through curve originated with wind farms, and is not generally conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines.> The minimum Voltage for 9 cycles does not allow enough time for breaker failure protection operation. 13 -15 cycles would be appropriate.> The Voltages presented are at the point of interconnection and are not directly translatable to machine relay Voltage settings.> Machine Volts per Hertz curves are a significant issue and are not addressed.> The UV performance of plant auxiliaries is a significant issue, and is not addressed.> We suggest that ANSI/IEEE Standards C37.102, C50 12, and C50.13 should be used and listed as references to this Standard.
Response: Thank you for your detailed response to this question. The SDT has clarified that generators are not required to install or set the relays to trip. The intent of the Standard is to provide a definition of the no trip boundary for generator relays. If the generator can remain on line during this boundary, no relay changes or modifications are required. The boundary defines generator relay settings for normally cleared three-phase fault on the transmission system and does not address transmission relay failures that would result in delayed clearing. The SDT recognizes the IEEE C37.102 requirement that generator protection should not trip on undervoltage, but should alarm. The proposed PRC-24-1 Standard does not require tripping, but rather defines a boundary when generators that are equipped with high and low voltage relays should not trip generators. Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions, addressing plant auxiliaries concerns. Machine Volts per Hertz capabilities were reviewed by the SDT. The upper boundary of the voltage duration curve in Attachment 2 is designed to accommodate those limits.		
CenterPoint Energy	No	a) Attachment 2 of PRC-024-2 is truncated at 4 seconds and does not define the duration of the 0.9 pu voltage level. CenterPoint Energy recommends the total duration of the 0.9 pu voltage level be established at a MINIMUM of 10 seconds. The basis for 10 seconds is for coordination with undervoltage load shedding (UVLS) systems. b) Attachment 2 has a step function profile. CenterPoint Energy has reviewed these proposed steps for voltage recovery to 0.9 pu and concurs with most proposed steps. However, CenterPoint Energy studies indicate an insufficient coordination margin at the proposed 0.30 seconds at 0.65 pu voltage point. Noting the CenterPoint Energy transmission grid is a compact and stout system, CenterPoint Energy believes it is highly unlikely many transmission systems can recover to a 0.65 voltage level in 18 cycles (0.30 seconds). To address this, CenterPoint Energy recommends reducing the number of steps. For this, as well as including a 0.9 pu voltage level ride-through for a minimum of 10 seconds, CenterPoint Energy recommends the data points (Time / Voltage) in the LVRT DURATION table be as follows: 0.15 / 0.000, 2.00 / 0.450, 3.00 / 0.750, and 10.00 / 0.900.
Response: Thank you for your detailed response to this question. Attachment 2 has been extended to 600 seconds. The profile of the voltage duration		

Organization	Yes or No	Question 4 Comment
curve is based on studies done in the Eastern and Western Interconnections. If you have studies that document longer recovery times, please share them with the SDT.		
Independent Electricity System Operator	No	Simulation results only add value when sufficient validation has been performed to provide confidence that good decision can be made on the basis of these simulations. Simulations by themselves are not enough. Were the simulations used in this exercise validated against actual performance? To cater for protection differences within jurisdictions, it would be better to label the jogs in the voltage characteristic with the corresponding physical meaning (e.g. maximum normal fault clearing, maximum delayed fault clearing) rather than assign specific times. Within Ontario, it is unclear whether the voltage curves are sufficient to accommodate present practice for delayed fault clearing. It is unclear in the curves whether the POI voltage is the positive sequence voltage or phase voltage. The meaning of per unit should also be clarified. For example, Ontario uses a 220kV voltage basis for a system operated as high as 250kV. Does 1.2PU mean 264 kV or 300kV? The over-voltage settings should be re-expressed to ensure the short duration over-voltages that follow lightning strikes and capacitor switching do not result in generator tripping.
Response: Thank you for your detailed response to this question. Validation against actual system performance is important. The simulations that were initially performed as part of this analysis had their genesis within WECC. On an ongoing basis, the Modeling & Validation Work Group validates system model performance against actual system events. The voltage ride-through curve provided in Attachment 2 of PRC-24-1 addresses specific performance that would be required over a wide range of system events and locations. The positive sequence models of the power system that were utilized in the performance analysis did include detailed machine representation accepted by IEEE which calculated shaft torques and other machine parameters. Clarification 1 currently indicates: "The per unit voltage base for this curve is the scheduled operating voltage as measured at the point of interconnection to the Bulk Electric System."		
Ameren	No	FERC 661-A applies to wind generator Voltage Ride Though (VRT) for a three phase fault. We disagree with PRC-024-1 now expanding it to all generators.R2.2.1 wording is confusing: it implies that the UV trip setting must be less than 9 cycles which conflicts with the LVRT curve and its interpretation for lessor voltage dips.
Response: Thank you for your detailed response to this question. The SDT has developed a technology neutral Standard that applies to all generators. Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions. The SDT has clarified that generators are not required to install or set the relays to trip. The SDT revised R2.1.1 as follows: " For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, not to exceed 9 cycles."		
First Solar	No	See response to the previous question. While this may envelope the probable range of voltages that may occur on the system, it does not sufficiently describe the response of the generating plant to these disturbances. To simply say that the protective relays should not trip lacks sufficient detail to apply to inverter based PV projects.
Response: Thank you for your response to this question. The SDT has developed a technology neutral Standard that applies to all generators. Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions. The SDT has clarified		

Organization	Yes or No	Question 4 Comment
that generators are not required to install or set the relays to trip.		
US Bureau of Reclamation	No	The SDT background material above states that the 9 cycle time is required by FERC Order 661-A. FERC Order 661-A applies to wind generators. We believe there is no convincing reliability based rationale to expand the scope of the FERC Order via this standard to include synchronous machines, noting that Genrators are already required (PRC-001-1) to coordinate settings with the host Transmission Operator.
Response: Thank you for your response to this question. The SDT has developed a technology neutral Standard that applies to all generators. Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions. The SDT has clarified that generators are not required to install or set the relays to trip.		
American Transmission Company	No	It would be beneficial to have the option of measuring the voltage at the generator bus or point of interconnection (POI), with the understanding that the proper voltage must be maintained at the POI.
Response: Thank you for your comment. The SDT specifically chose the point of interconnection because that is where the faults occur that this Standard is intended to address. The SDT has provided additional assumptions for the calculation of relay settings on the basis of the voltage as measured at the POI.		
Luminant Power	No	
E.ON U.S.	No	
AWEA	No	
American Wind Energy Association	No	
Veolia Environmental Services	No	
Lakeland Electric	No	
Manitoba Hydro	No	

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<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>American Electric Power</td><td>No</td><td></td></tr>
<tr><td>MRO NERC Standards Review Subcommittee</td><td>Yes</td><td>Where would be the appropriate voltage measurement point? (Generator bus or POI)</td></tr>
<tr><td colspan="3">Response: Thank you for providing a response to this question. The Standard is concerned with generator response to excursions on the transmission system, so the voltage profile in Attachment 2 is defined at the transmission voltage (or POI) level. The equivalent profile at the generator terminals depends on the characteristics of the equipment at each facility, so the Generator Owner would have to determine how it affects his equipment and evaluate accordingly.</td></tr>
<tr><td>SERC Dynamics Review Subcommittee (DRS)</td><td>Yes</td><td>However, the wording used in section R2.2.1 is confusing. The words should be changed to "For three-phase transmission system zone 1 faults with Normal Clearing, generator relaying shall be set longer than the expected fault clearing time, but not greater than nine cycles."</td></tr>
<tr><td colspan="3">Response: Thank you for providing a response to this question. The SDT has clarified the language of R2.2.1 (now R2.1.1. in the revised standard) Standard language.</td></tr>
<tr><td>Entergy Fossil Operations</td><td>Yes</td><td>I do not know enough about this to comment either way</td></tr>
<tr><td colspan="3">Response: The SDT will add clarifications to the Standard based on industry inputs.</td></tr>
<tr><td>IRC Standards Review Committee</td><td>Yes</td><td>From a system operator's perspective, we think these parameters are appropriate to prevent unnecessary tripping of the generators, which may otherwise give rise to unreliability, while minimizing their expose to prolonged period of under and overvoltages.</td></tr>
<tr><td colspan="3">Response: Thank you for providing a response to this question.</td></tr>
<tr><td>Old Dominion Electric Cooperative</td><td>Yes</td><td>In general, I agree with your curve. I need to review more completely before I am ready to vote Yes on it.</td></tr>
<tr><td colspan="3">Response: Thank you or providing a response to the question. We welcome any recommendations that would help to clarify the document.</td></tr>
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Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	The applicability of the curve is limited to the protective relays addressed by the standard. This curve is not meaningful if the plants were going to trip due to other causes. See our response to Question #9.
Response: Thanks you for your response to the questions. Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
PJM Interconnection	Yes	In R2.2.1, replace -greater- with -faster- or -slower-, whichever is correct. In R2.2.3 replace -intended- with -required-. In R4, replace -written- with -documented-. In R5, add an -s- to -System- in the parentheses. In R3, R4 and R5 - Concerned with the GO responsibility to send to their RC, PC, TO and TP. Would rather see the GO responsibility be to just to respond to any RC, PC, TO and TP requests.
Response: Thank you for your comments. The SDT has modified the Standard to address the language concerns relative to R2.2.1 (now 2.1.1 in the revised standard) and R2.2.3 (now 2.1.3). The SDT prefers the choice of written as opposed to documented in R4. In R3 and R5 all the named entities must receive the information. In R4 we agree that only the requesting entity must receive the information.		
Dominion	Yes	We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that " For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected "We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system under voltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator (2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations? If the standard is intended to apply to volts per hertz relays, suggest:1. Revising footnote 1 to specifically include volts per hertz relays.2. Revise Steps 4.2.1 and 4.2.2 to specifically include volts per hertz relays.3. That the standard should incorporate specific guidance for facilities using volts per hertz logics and include a graph showing the voltage and frequency excursions in terms of volts per hertz.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions, addressing the auxiliary systems concern. With respect to steady state evaluations versus dynamic simulations, the Standard does not preclude the application of either. The SDT agrees and has added volts per hertz relays among the listed items in footnote 1.		
Northeast Power Coordinating Council	Yes	Referencing R5 and R6 of the Standard: The Reliability Coordinator should be give veto power over exceptions to the requirements herein. Should the Generator Owner/Operator not be able to, or be unwilling to, make changes to setpoints to come into compliance with this Standard, the Reliability Coordinator should be given the authority to invoke required mitigation, such as requiring the Generator Owner/Operator to contract for compensatory load shedding up to the total

Organization	Yes or No	Question 4 Comment
		amount of MW of each generating unit that fails to comply with the required setpoints. In addition, The "Off-Nominal Frequency Capability Curve" in Attachment 1 does not coordinate with the underfrequency load shedding (UFLS) program design parameters proposed by the NERC Underfrequency Load Shedding Standard Drafting Team for Project 2007-01. The misccoordination occurs in the time range approximately between 5 and 10 seconds. This miscoordination can be eliminated by extending the horizontal line at 57.8 Hz to 5 seconds and revising the diagonal line to have endpoints at 57.8 Hz/5s and 59.5 Hz/1800s. This modification will provide coordination with the UFLS program design parameters while still maintaining coordination with turbine-generator capability.Due to the time scale on the graph in Attachment 2, the curves do not indicate the time at which the transient overvoltage and undervoltage requirements end, at which point the continuous voltage requirements would be applicable. Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above:> Concerning Attachment 1, we believe this is mainly present to infer that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled. > A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed relaying not to trip during" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer.> Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted."> Concerning A.R2, this Standard addresses setting of voltage relays based on voltage at the point of interconnection, which is not directly translatable to voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard.We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that " For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected "We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system undervoltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator?(2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations?

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT has captured what we believe are the main points of your comment sand has provided responses below:
• RC should have veto power over exemptions – The SDT believes it is the responsibility of the GO to determine the capability of the existing unit. The judgment as to validity of an exemption is a compliance matter.
• RC should have authority to decide mitigation, e.g., compensatory load shedding – The SDT believes mitigation of inability to comply with a Standard is a compliance matter.
• UFLS mis-coordination – The UFLS SDT and this Standard Drafting Team conferred and resolved the mis-coordiantion. The resolution that was mutually agreed to was for the UFLS SDT to modify its Standard to accommodate the frequency curve in this Standard.
• PRC-024 should not interfere with UFLS – The two teams have coordinated the frequency curves and strategies.
• State that settings shall be determined to prevent machine damage in consultation with manufacturers' recommendation – The SDT developed the curves in accordance with manufacturer's recommendations and the Standard includes an exemption process for existing generators.
• Are settings permitted on the curve? No, settings are not permitted on the curve/line and the Standard has been modified to reflect this more clearly. --
• POI versus generator terminal – The SDT specifically chose the point of interconnection because that is where the faults that this Standard is intended to address occur.
• Auxiliary systems relays and Steady state versus dynamic simulation – Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions, addressing the auxiliary systems concern. With respect to steady state evaluations versus dynamic simulations, the Standard does not preclude the application of either. The SDT agrees and has added volts per hertz relays among the listed items in footnote 1.</td></tr>
<tr><td>SERC Dynamics Review Subcommittee (DRS)</td><td>Yes</td><td>1. We recommend deleting the proposed section R2.2.2. If not deleted, change: "meet a shorter voltage ride through" to "meet a less stringent voltage ride through".
2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field.
3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request"</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The SDT agrees and has modified the Standard to reflect this. In the revised standard, the phrase, "less stringent" is used. (See 2.1.2)
2. The SDT intends this requirement to ensure timely notification of equipment changes to the PA and 30 days is a reasonable duration for the time horizon of the PA.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
3. **The SDT agrees and has modified the standard to reflect this.**		
Kansas City Power & Light	Yes	Please consider including the Balancing Authority as an entity for the Generator Owner to provide settings information in requirements R3 & R4 since the BA is an entity that has a direct relationship with the operational status of generating stations. R5: Do not agree with the bulleted item where increasing the capability of a generator by 10% is a reason for exemption expiration. As an example, turbine or boiler enhancements can result in greater efficiencies and resulting in an increase of generator capability with no change to the generator or its protection capabilities whatsoever. Recommend removal of this bulleted item. R5: The generator exciter voltage regulator contains protective relay settings such as Volts/Hertz, undervoltage, overvoltage, underfrequency that will also trip the Unit. Is the exciter voltage regulator considered to be part of the generator protective relay system? If so, would a limitation of the exciter voltage regulator be allowed as an exception to the standard or, since the protective system is excluded, would R5 mandate that the exciter voltage regulator be replaced to remove the exception? This issue should be clarified in R5.
Response: The SDT does not observe a reliability need to provide these setting data to the Balancing Authority. **The SDT intends for a GO who decides to increase capability of its unit by a significant amount (now 10%) to also address the technical limitation cited in its exemption.** **The NERC Glossary definition of Protective System does not include voltage regulator. However, the SDT intends this Standard to include all protective functions and relays that directly trip the generator based on frequency and voltage excursions, regardless of where they are located.**		
MRO NERC Standards Review Subcommittee	Yes	It would be good to have the option of measuring the voltage at the Generator bus or POI. With the understanding that the voltage must be maintained of the POI.
Response: Thank you for your comment. The SDT agrees that it is the voltage at the POI that must be maintained. The Standard is concerned with generator response to excursions on the transmission system, so the voltage profile in Attachment 2 is defined at the transmission voltage (or POI) level. The equivalent profile at the generator terminals depends on the characteristics of the equipment at each facility.		
FirstEnergy	Yes	1. FE's consensus is that the PRC-024 allowable under-frequency vs. time tripping curve is too tight. By too tight, we mean that the LP turbine buckets and blades are much more tolerant of off freq operation than the proposed tables. Comparing them to the old ECAR curves and allowable tripping times shows they are more stringent. Given how seldom these events occur, (never happened yet in the Eastern Interconnect) expending more of this capacity appears justified. 2. Section A5 Implementation schedule - it may not give sufficient time to implement these requirements. We suggest an

Organization	Yes or No	Question 4 Comment
		additional year as follows: no less than 33% within 2 years of effective date no less than 66% within 3 years of effective date no less than 100% within 4 years of effective date 3. R1.2 Should say off-nominal not off-normal. 4. R2.1 Suggest changing the word "measured" to "experienced". 5. In R5, we suggest changing the first bullet to read: "The equipment causing the limitation is modified, upgraded or replaced with equipment that removes the technical limitation.", and then delete the second bullet. 6. Requirements 3, 4 and 6 specify that the Generator Owner shall provide information to RCs, PCs, TOPs, and TPs that monitor or model the associated unit; however, there is no requirement for these entities to identify themselves to the Generator Owner. How will the Generator Owner know they have identified all of the entities that need the information? 7. In R5, the Generator Owner is granted an exception from requirements R1 or R2 simply by providing documentation of a equipment limitations. There is no independent view of the appropriateness of this exception. The drafting team should consider requiring independent verification of the equipment limitation prior to the granting of an exception to the requirements of the standard. 8. Sec. D References - Is this intended to be part of the standard? If so, it would be helpful if it was linked to the white paper so that we can review it. 9. In Requirements R3 through R6, the SDT may want to consider adding the Transmission Owner as another entity who may need this information. 10. R2.2.1 may need to be re-worded as it requires that protection trip in no greater than 9 cycles. We are not aware of a disadvantage to the system if the tripping takes longer than 9 cycles.

Response:

1. **The SDT intends for GOs to set its relays as tight as possible and not merely on the curve/line.**
2. **The SDT set the timeframe by consensus among team members and the companies they represent. Stakeholder comments have not thus far objected to the implementation schedule. On this basis the SDT is leaving the schedule as proposed.**
3. **The SDT agrees and has made the change.**
4. **The SDT has modified the wording in R2.**
5. **The intent of R5 is to require eliminating the exception if the generator is upgraded by 10% or more.**
6. **The GO is expected to know what entity is its RC, PC, TO, and TP.**
7. **The drafting team considered requiring an independent evaluation of existing generator exceptions and determined that it is not practical.**

Organization	Yes or No	Question 4 Comment
8. No referenced documents are part of the Standard. **9. The SDT considered including the Transmission Owner and determined that the Transmission Operator is the appropriate organization to receive the information.** **10. The 9 cycle maximum clearing time is intentional. It is not a system consideration; it is because generators cannot withstand zero voltage at the POI for long periods of time.**		
IRC Standards Review Committee	Yes	a. R5: The wording "the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation." is not written in a way to hold an entity responsible for any action. We suggest to reword it such that it places a responsibility to the Generator to seek approval for an exception, as follows: "the Generator Owner shall obtain approval for an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation through the submission of documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit within 30 days of identifying the equipment limitation. Along with this proposed change, there is also a need for the entities receiving the approval request to respond to the request. Another requirement is needed to complete this process. b. The latter part of R5 should be reworded to hold an entity responsible for the needed actions associated with expiring the exception such that the requirement is measurable and enforceable. c. R6: It is unclear to us what purpose this requirement serves. If R5 is to be revised as we suggest (see above), then the "limitation" in question will be presented with technical justification in the request for approval. The receiving entities (RC, PC, TOP and TP) will have a chance to accept or reject the request with due consideration of the technical argument. This is part of the approval request process; hence we do not see the need for R6 if R5 is to be reworded. If a remand process needs to be stipulated, then inclusion in R5 a requirement for the receiving entity(ies) to respond to the request - either approving or disproving the with a rationale, would suffice.
Response: Thank you for your comment. **a. The required action is for the GO to provide documentation of the equipment limitation. The SDT believes it is the GO's responsibility to determine any limitations on existing generators' ability to meet the Standard.** **b. The GO is responsible for meeting the requirements when an exception expires.** **c. R6 (R4 in the revised standard) provides the RC, PC, TO, and TP with an opportunity to seek clarification concerning existing generator limitations in meeting the Standard.**		
Constellation Power	Yes	The 4 kV protection that includes under frequency and under voltage relays trip the generator in some of our plants. The

Organization	Yes or No	Question 4 Comment
Generation & Constellation Nuclear		SDT needs to clarify whether this standard applies to such protection.
Response: Thank you for your comment. The Standard applies to setting of voltage and frequency relays that directly protect the generator.		
Southern Company	Yes	1. We recommend deleting the proposed section R2.2.2. If not deleted, change "meet a shorter voltage ride through" to "meet a less stringent voltage ride through". 2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field. 3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request" 4. How did the SDT translate the transient voltage excursion plot to the cumulative voltage curve? 5. The voltage ride through curve was said to be cumulative, this should be specified on the curve. 6. How can we prove that our static voltage curve coordinates with this cumulative curve 7. Implementation schedule we believe that the unit size should be considered, and that the most critical units should be worked on first. Completing 33% each year is too ambitious for those members that have > 300 units. 8. What regions are working on voltage ride through and Underfrequency (ufls and undefrequency tripping of generators) 9. Should the PRC-024 SDT wait until the regions have completed their work? 10. Generator engineers do not see a relevance for a voltage ride-through for any generator other than wind.
Response: Thank you for your comment. **1. The SDT agrees and has modified the standard to reflect this.** **2. The SDT intends this requirement to ensure timely notification of equipment changes to the PA and 30 days is a reasonable duration for the Time Horizon of the PA.** **3. The SDT agrees and has modified the Standard to reflect this.** **4. The SDT analyzed the amount of time the voltage remained outside of the required range in each of the events modeled.** **5. The SDT has clarified the language.** **6. A cumulative curve was selected to coordinate with relays that measure elapsed time.** **7. The SDT set the timeframe by consensus among team members and the companies they represent. Stakeholder comments have not thus far**		

Organization	Yes or No	Question 4 Comment
objected to the implementation schedule. On this basis the SDT is leaving the schedule as proposed. **8. At the recommendation of FERC and NERC, the SDT has coordinated the UF relay curve with the NERC UFLS SDT members input.** **9. At the recommendation of FERC and NERC, the SDT has coordinated the UF relay curve with the NERC UFLS SDT members input.** **10. The SDT has taken the direction to develop a Standard that is technology neutral.**		
Converteam Naval Systems Inc.	Yes	0. (Overall) This is a good document that has good background study and contains a lot of expertise; 1. (Voltage definition inconsistency)In the LVRT curves, it talks about the voltage at the point of interconnection. However, in R2.1 it uses voltage at the generator terminals. I think there is a little inconsistency between these two. It would be good to just use one of them, preferably the former one. The reason is that different generator plants might have different impedance between the generator terminals and the points of interconnection, so defining the voltage at the terminals poses a little unfairness. Another part of the reason is that for transmission protection purpose, it should ends at the point of interconnection. 2. (Voltage range inconsistency)The voltage range is 0.9-1.1pu in the VRT curve, but it says 0.95-1.05 in R2.1. It would be good to make it consistent. 3. (Date point missing) In the table supporting the VRT curves, the 0.95 and 1.05pu data are missing. 4. (Priority) WECC and MRO have different VRT curves. Which one will override which one at the end? Will the NERC PRC-024 take priority than the Regional Entities? 5. Was reactive power support during faults considered in the draft group? Will it be required in the future Thanks
Response: Thank you for your comment. **0. Thank you!** **1. The Standard applies to transient voltage excursions at the POI. R2.1 addresses steady state voltages at the generator terminals.** **2. The VRT curve addresses the transient voltage event. R2.1 addresses steady state conditions, outside the range of the VRT curve.** **3. The table addresses the transient voltage event and does not address steady state conditions.** **4. This proposed standard is a NERC standard. The SDT is not addressing current or future regional Standards.** **5. The Standard addresses voltage ride through. Reactive power and voltage support are important considerations in determining if a generator will meet the Standard. Methods to meet the Standard requirement are not specified in the Standard.**		
Consumers Energy	Yes	Please see comments on Question 3.

Organization	Yes or No	Question 4 Comment
Company		
Response: Thank you for your comment. Please see responses to Question 3.		
Old Dominion Electric Cooperative	Yes	Provide some insight on Technical Exceptions for generators that cannot met these requirements (the CIP TFE process might be useful in this)
Response: Thank you for your comment. The SDT believes it is the responsibility of the GO to determine the capability of the existing units to meet the Standard.		
Southern California Edison Company	Yes	The curves and tables in the attachments require additional clarification.
Response: Thank you for your comments. Additional clarification has been added.		
Progress Energy, Inc.	Yes	1. Recommend deleting proposed R2.2.2. If not deleted the language needs to be clarified as follows: "meet a shorter voltage ride through" should be changed to "meet a less stringent voltage ride through". 2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field. 3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request" 4. The purpose and the applicability of the standard needs to be revised to clearly specify that the scope of PRC-024-1 only applies to main generator protective relaying and excludes protective functions associated with plant auxiliary equipment.
Response: Thank you for your comments. **1. The SDT agrees and has modified the Standard to reflect this.** **2. The SDT intends this requirement to ensure timely notification of equipment changes to the PA and 30 days is a reasonable duration for the Time Horizon of the PA.** **3. The SDT agrees and has modified the Standard to reflect this.** **4. The Standard has been modified and now applies to overall new generator performance.**		
NIPSCo	Yes	R4 These groups should already have this information. The coordinators or planners should have proof and be able to provide this information now.R5 Normally would not accumulate enough time in the under-frequency zone to be a danger to the turbine blades but under unusual circumstances might accumulate too much time and not be able to continue to operate

Organization	Yes or No	Question 4 Comment
		in the under-frequency region that is being specified. We might not have enough time to wait for the 30 day period.
Response: Thank you for your comment. • **The purpose of the Standard is to assure that the relay setting information is available to the groups that require it.** • **Existing generators that are not able to meet the Standard are able to obtain an exception.**		
Northeast Utilities	Yes	R2.2.1 seems to imply that a generator must set an undervoltage trip with a time delay of no more than 9 cycles. This seems to conflict with the intent of PRC-024. Is the intent perhaps to require the TO to clear Zone 1 faults in no more than 9 cycles? Or is the intent to allow the GO to set the time delay as low as 9 cycles and no less? I suggest the latter.R3, R4, and R5 - This information should be provided to the owner of any UFLS or UVLS as well.
Response: Thank you for your comment. The intent is to allow TOs to reduce the required 9 cycle ride through requirement in cases where transmission system design allows faster clearing.		
Hydro-Québec TransEnergie (HQT)	Yes	Referencing R5 and R6 of the Standard: The Reliability Coordinator should be give veto power over exceptions to the requirements herein. Should the Generator Owner/Operator not be able to, or be unwilling to, make changes to setpoints to come into compliance with this Standard, the Reliability Coordinator should be given the authority to invoke required mitigation, such as requiring the Generator Owner/Operator to contract for compensatory load shedding up to the total amount of MW of each generating unit that fails to comply with the required setpoints. In addition, The "Off-Nominal Frequency Capability Curve" in Attachment 1 does not coordinate with the underfrequency load shedding (UFLS) program design parameters proposed by the NERC Underfrequency Load Shedding Standard Drafting Team for Project 2007-01. The misccoordination occurs in the time range approximatley between 5 and 10 seconds. This miscoordination can be eliminated by extending the horizontal line at 57.8 Hz to 5 seconds and revising the diagonal line to have endpoints at 57.8 Hz/5s and 59.5 Hz/1800s. This modification will provide coordination with the UFLS program design parameters while still maintaining coordination with turbine-generator capability. Due to the time scale on the graph in Attachment 2, the curves do not indicate the time at which the transient overvoltage and undervoltage requirements end, at which point the continuous voltage requirements would be applicable. Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above:> Concerning Attachment 1, we believe this is mainly present to infer that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled. > A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed relaying not to trip during" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective

Organization	Yes or No	Question 4 Comment
		devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer.> Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted."> Concerning A.R2, this Standard addresses setting of voltage relays based on voltage at the point of interconnection, which is not directly translatable to voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard. We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that " For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected "We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system undervoltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator?(2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations?

Response: Thank you for your comment.

- **The GO has the responsibility for determining the capability of existing generators and their ability to meet this Standard. How the power system deals with the inability of an existing generator to meet the Standard requirements is not addressed in this Standard.**
- **The UFLS SDT and this Standard Drafting Team conferred and have coordinated the frequency curves and strategies.**
- **The voltage curve ends at 1000 seconds. Steady state limits apply after 600 seconds.**
- **Clarification has been added that the Standard does not require voltage or frequency protective relays to be installed or enabled.**
- **Clarification has been added concerning setting relays exactly on the curve.**
- **Clarification has been added concerning assumptions to be made when calculating generator terminal voltage settings that correspond to required POI limits.**
- **The Standard has been modified to be a new generator performance Standard.**
- **With respect to steady state evaluations versus dynamic simulations, the Standard does not preclude the application of either.**

Organization	Yes or No	Question 4 Comment
AESO	Yes	In addition to the SRC ISO/RTO comments the AESO would like to add: As we understand it, the intent of this standard is to ensure that the generators ride through certain levels of frequency and voltage excursions, yet it only addresses the generator protection. We feel it must also address the protection and capabilities of the auxiliaries, unit transformers, lines, etc. If any of these trip off due to the same excursions that the generator is required to ride through, then the generator will be down and the standard will not have achieved its goal.
Response: Thank you for your comment. Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.		
Duke Energy	Yes	The issue typically addressed by international grid codes is an over-all plant performance standard and plant dynamic studies are performed to evaluate the impact on in-plant systems. Standards applicable to only generator protection might give a false sense that a plant could survive the transients and the reliability of the BES would be just as adversely impacted if large plants were to trip for causes other than a main generator relay. The basis and reliability benefit for voltage ride through transients should be clarified. Generator UF relays must coordinate with grid UFLS relaying. Some areas may apply UVLS and logic dictates that the coordination of that protection with a generator ride through criteria should be specified. Recommend that the scope of "equipment" that can be granted an exception be limited in some way or explicitly qualified. Otherwise, plant performance can be dictated by less-consequential auxiliary equipment (e.g. variable speed drives with UV settings per manufacturer standard instructions). Because R5 grants exception automatically in response to the GO providing documentation of any limitation. R5 bullet 2 - recommend changing "generator nameplate capacity rating" to "generator gross Real Power capability". The existing words are too general and including 'nameplate' is confusing.
Response: Thank you for your comment. • **The Standard has been modified to require new generators to ride through voltage and frequency excursions.** • **The UFLS SDT and this Standard Drafting Team conferred and have coordinated the frequency curves and strategies.** • **The GO has the responsibility for determining the capability of existing generators and their ability to meet this Standard.** • **The SDT used the term, "continuous capacity rating" instead of "nameplate capacity" in the revised standard.**		
New York Independent System Operator	Yes	Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above:> Concerning Attachment 1, we believe this is mainly present to insure that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine

Organization	Yes or No	Question 4 Comment
		manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled.> A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed relaying not to trip during" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective device, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and Voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer.> Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this questions will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted."> Concerning A.R2, this Standard addresses setting of Voltage relays based on Voltage at the point of interconnection, which is not directly translatable to Voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard.

Response: Thank you for your comment.

- **The UFLS SDT and this Standard Drafting Team conferred and have coordinated the frequency curves and strategies.**
- **Determining existing generator capability is the responsibility of the GO.**
- **Clarification has been added to make it clearer that the Standard does not require installing voltage or frequency protection relays nor does it require setting any relays at the curve values.**

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	Please clarify if there is an expectation/requirement for new units to install voltage and frequency protective relays.

Response: Thank you for your comment. There is no requirement for any generator to install or have voltage or frequency protective relays. Clarification has been added.

Organization	Yes or No	Question 4 Comment
CenterPoint Energy	Yes	a) CenterPoint Energy is concerned with what appears to be a lack of consistency and coordination between standards efforts. Considering PRC-023, CenterPoint Energy believes it is illogical to have transmission relay loadability requirements based on 0.85 pu system voltage for an extended period (such as, 15 minutes) to allow system operators to take remedial actions, while exempting generators from comparable requirements. For another example, it appears this proposed standard is not consistent with that being proposed for under-frequency load shedding systems that can help prevent cascading outages. b) Requirements, such as R2.2.1 and R2.2.2, are essentially fill-in-the-blank, location-specific criteria that are unnecessary

Organization	Yes or No	Question 4 Comment
		and could have unintended consequences. Location-specific criteria can change over time with additions and modifications of the transmission system. Entities will have no incentives to voluntarily exceed the minimum required criteria, even though their plant has a greater ride-though capability. R2.2.1 further allows relaying to be set on actual fault clearing times, instead of the 9 cycles indicated in Attachment 2. In addition, R2.2.2 allows the use of location-specific criteria, but only if such criteria are less stringent. CenterPoint Energy believes NERC reliability standards should not include fill-in-the-blank, location-specific criteria. CenterPoint Energy recommends modifying R2.2.1 to reference Attachment 2 and to clarify the ride-through criteria is zero voltage for 0.15 seconds (9 cycles). CenterPoint Energy recommends deleting R2.2.2. c) R5 allows generating plants to meet less stringent criteria if generator manufacturer literature indicates limitations, which would further erode system support from generation resources. It does not appear there is any process to substantiate the legitimacy of such limitations. CenterPoint Energy recommends deleting R5 and associated references.
Response: Thank you for your comment. **a) The Standard has been modified to require new generators to ride through voltage and frequency excursions. The SDT has coordinated the development of the UF relay curve with UFLS SDT.** **b) Requirements R2.2.1 and R 2.2.2 (new R2.1.2) allow the TO to relax the voltage ride through requirements in specific cases where the transmission system is designed to accommodate reduced generator performance.** **c) New R3 exempts existing generators that are not capable of meeting the Standard's requirements from having to do so. The GO is responsible for determining the generator's capabilities.**		
Independent Electricity System Operator	Yes	a. R5: The wording "the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation." is not written in a way to hold an entity responsible for any action. We suggest to reword it such that it places a responsibilility to the Generator to seek approval for an exception, as follows:"the Generator Owner shall obtain approval for an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation through the submission of documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit within 30 days of identifying the equipment limitation." The requirement for getting non-conforming protection approved should be so stipulated to put the onus for mitigating actions on the Generator Owners. For example, in the case of non-conforming underfrequency settings, the requesting Generator Owner should be required to demonstrate that mitigating (i.e. arrangements for additional compensating load shedding) measures have been arranged with the Balancing Authority in their submission. Equipment settings that infringe upon the curves may be implemented only after approval is granted by the appropriate entities. Along with this proposed change, there is also a need for the entities receiving the approval request to respond to the request. Another requirement is needed to complete this process.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>b. The latter part of R5 should be reworded to hold an entity responsible for the needed actions associated with expiring the exception such that the requirement is measurable and enforceable.

c. R6: It is unclear to us what purpose this requirement serves. If R5 is to be revised as we suggest (see above), then the "limitation" in question will be presented with technical justification in the request for approval. The receiving entities (RC, PC, TOP and TP) will have a chance to accept or reject the request with due consideration of the technical argument. This is part of the approval request process, hence we do not see the need for R6 if R5 is to be reworded. If a remand process needs to be stipulated, then inclusion in R5 a requirement for the receiving entity(ies) to respond to the request - either approving or disproving the with a rationale, would suffice.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

a) The required action in the new R3 is for the GO to provide documentation of the equipment limitation(s) to the RC, PC, TO, and TP. The GO is not required to seek approval.

b) The SDT believes that new R3 is measurable and enforceable.

c) The purpose of new R3 is to exempt existing generators that are not capable of meeting the Standard from having to do so.</td></tr>
<tr><td>Ameren</td><td>Yes</td><td>This standard could be ineffective if someone’s auxiliary power protection trips out on low voltage or frequency and brings the unit down before the generator protection. Those settings on the aux buses are there to protect the equipment from failure since most of the downstream loads such as motors and electronics won’t ride through an excursion as well as large T/G sets. We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard. Reporting mechanism in R3 and R4 raises some commercial concerns. We prefer a secure repository of reporting to the RRO. Then only those who do have valid reasons for studies or monitoring could be granted access to the information. Footnote 1 expands 'protective relays' definition to include voltage regulator, etc. Instead state that only direct trip elements (functions) in the voltage regulator and exciter are included, if that's the intent. It should be made very clear.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The Standard has been modified to require new generators to ride through voltage and frequency excursions.
The SDT recognizes that the information required to be reported must be protected appropriately and expects the receiving organizations will fulfill all of their information protection obligations.
Clarification has been added to footnote 1.</td></tr>
<tr><td>PPL Energy Plus</td><td>Yes</td><td>PPL is concerned with the following concepts in the standard:

1) The standard applies equally to asynchronous and synchronous machines, salient pole and round rotor machines,</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		photovoltaic, and other resources and as such the standard does not appear to recognize that these technologies respond differently to voltage and frequency excursions. 2) Better clarity of generator owner and transmission owner roles regarding changing existing fault clearing times is needed in the proposed standard. 3) R2.2 requires further clarity regarding relay settings. 4) R3 and R4 look the same. 5) The reference paper under Section D needs a thorough review by the industry.
Response: Thank you for your comment. **1. The SDT has taken the direction to develop a Standard that is technology neutral.** **2. The TO is allowed to relax the relay setting Standard (shorter durations or higher minimum voltages and or lower maximum voltages) if the full capability of the Standards is not required in specific instances.** **3. Further clarification has been added.** **4. Old R3 and old R4 are combined into the new R6.** **5. The SDT welcomes thorough industry review of the reference paper.**		
US Bureau of Reclamation	Yes	Requirements R3 and R4 place a coordinating role on the Generator Owner to provide trip settings to four entities, the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner. We believe it is more appropriate for the Generator Owner to coordinate settings with a single Transmission entity since the purpose of the Standard is "... to support transmission system stability during voltage and frequency excursions." and for the Transmission entity to further coordinate if necessary. The Transmission entity is in a better position to know what additional entities, if any should be involved. For the data points provided in the Attachment 2, HVRT DURATION and LVRT DURATION, we recommend both time and voltage units of measure be provided.
Response: Thank you for your comment. Old R3 and old R4 are combined into the new R6. The SDT agrees with the comment and has added clarification to the voltage and time units in Attachment 2		
PJM Interconnection	Yes	
Dominion	Yes	

Organization	Yes or No	Question 4 Comment
FirstEnergy	Yes	
Luminant Power	Yes	
Consumers Energy Company	Yes	
E.ON U.S.	Yes	
AWEA	Yes	
American Wind Energy Association	Yes	
Veolia Environmental Services	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
NIPSCo	Yes	
Northeast Utilities	Yes	
American Electric Power	Yes	
American Transmission Company	Yes	

5. Coordination between UFLS programs and generator frequency tripping is especially a concern in islanded situations. Is the connection voltage of ≥100kV, the size threshold for generator units 20 MVA and greater and 75 MVA for multiple units at a single site, sufficient to address this concern? If not, please explain in the comment area.

Summary Consideration:

Most respondents agreed with the proposal.

The major comment issues raised are:

1) All operating units affect frequency excursion recovery regardless of size or voltage
2) Applicability should be on a case-by-case basis
3) Only large units are significant to stability

The GV SDT considerations for the major comment issues are:

- After consideration of comments and discussion with NERC staff, the SDT agrees with the majority position that the applicability of facilities that meet the Compliance Registry Criteria is sufficient to address coordination between UFLS programs and generator tripping. The language that duplicated the language from the Compliance Registry Criteria is not necessary to include in the applicability section of the standard, and was removed from the revised standard. The SDT does not believe that applicability of generating facilities should be assigned to other parties to determine on a case-by-case basis. Nor does the SDT believe that applicability should be limited to generating facilities larger than what is defined in the Compliance Registry Criteria.

Organization	Yes or No	Question 5 Comment
NERC System Protection and Control Subcommittee (SPCS)	No	The interconnection Voltage is not relevant, only the amount of generation potentially lost to the system.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the		

Organization	Yes or No	Question 5 Comment
applicability to Generator Owners as described in the Compliance Registry Criteria.		
Northeast Power Coordinating Council	No	Both bullets should be checked above (form will not accept).Reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage. We are concerned that the generator unit capacity thresholds are set too high. Given the tolerances in UFLS program design, the unit capacity thresholds should be established to ensure that 99 percent of the generation in a system complies with the requirements of this standard. The SDT should identify unit capacity thresholds on this basis, similar to how thresholds were developed in MOD-026.The interconnection voltage is not relevant, only the amount of generation potentially lost to the system. Some sub-regions, employing a UFLS Program, are dependent on Generator Owners/Operators meeting the specifications for generator Underfrequency setpoints in order to maintain a viable UFLS Program. For sub-regions where a large percentage of the total generation fleet is comprised of individual units < 20 MVA and connected to buses < 100 kV, the contribution of these units to the overall success of the sub-regions UFLS Program are more pronounced. It is suggested that the threshold should be established by referring to the requirements of the Region or as established by the Reliability Coordinator (sub-region). As an alternative, it is suggested that all generating units operating in a Reliability Coordinators' or RTO/ISO's market system, regardless of size, shall follow this Standard based on their materiality to the reliability of the bulk power system.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria.		
IRC Standards Review Committee	No	There should not be any exemption of the coordination on frequency trip setting. In an islanded situation, each generator's status is critical to ensuring that frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not holding the smaller generators subject to the requirements associated with generator frequency tripping exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria.		
Constellation Power Generation & Constellation Nuclear	No	Reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage. We are concerned that the generator unit capacity thresholds are set too high. Given the tolerances in UFLS program design, the unit capacity thresholds should be established to

Organization	Yes or No	Question 5 Comment
		ensure that 99 percent of the generation in a system complies with the requirements of this standard. The SDT should identify unit capacity thresholds on this basis, similar to how thresholds were developed in MOD-026.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. Extending the applicability to units beyond those covered under the Registry Criteria would make those units subject to all Generator Owner requirements in all other Standards.		
Southern Company	No	The unit size and plant size seem to be conservatively small. From a practical standpoint, our focus in this standard should be on the largest units, those that are most cricital in the reliability. A more reasonable limit would be 100MVA generator units and 200 MVA for multiple units at a single site.
Response: Thank you for your comment. The SDT believes that exempting units smaller than 100 MVA or sites smaller than 200 MVA would put the reliability of the Bulk Electric System at risk during a frequency excursion. This is especially true in islanding situations where smaller units may predominate within a particular island.		
E.ON U.S.	No	E.ON U.S. believes that the standard should apply to facilities at 200 kV and above in order to be consistent with equipment thresholds of other NERC standards.
Response: Thank you for your comment. The SDT believes that exempting units connected at voltages less than 200 kV would put the reliability of the Bulk Electric System at risk during a frequency excursion. This is especially true in islanding situations where units connected at less than 200 kV may predominate within a particular island.		
Veolia Environmental Services	No	Additional criteria would be useful to identify units that are critical to the BES. If a BA and/or TOP has identified a unit a non-critical, then such a unit should be exempt from this standard regardless of size and connection voltage.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. The SDT feels that all units that meet the Registry Criteria are of importance to the grid, especially during frequency excursions.		
Basin Electric Power Cooperative	No	This is likely to be something that has to be applied on a case by case basis, with consideration given to how many units we have that would not be covered by some sort of coordinated UFLS/generation protection settings. There is some latitude to make exceptions, but in the future, we may have many more units that fit this category, and then this becomes a big issue. Units which trip too soon will just impact the load shedding program unless a corresponding amount of load is shed at essentially the same time and more or less at that same location.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. The SDT does not agree that requirements should be applied on a case by case basis.		
Northeast Utilities	No	Significant generator capacity may be connected at distribution voltages and set with sensitive anti-islanding frequency/voltage setpoints. These generators need to report their setpoint data to the owner of any UFLS/UVLS systems that may be affected by the generator performance. This can be a significant amount of generation relative to the size of the UFLS/UVLS program.Consideration should also be given as to whether the requirements should apply to generators where the site aggregate is >20MVA.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. Extending the applicability to units beyond those covered under the Registry Criteria would make those units subject to all Generator Owner requirements in all other Standards.		
Hydro-Québec TransEnergie (HQT)	No	Reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage. We are concerned that the generator unit capacity thresholds are set too high. Given the tolerances in UFLS program design, the unit capacity thresholds should be established to ensure that 99 percent of the generation in a system complies with the requirements of this standard. The SDT should identify unit capacity thresholds on this basis, similar to how thresholds were developed in MOD-026.The interconnection voltage is not relevant, only the amount of generation potentially lost to the system.Some sub-regions, employing a UFLS Program, are dependent on Generator Owners/Operators meeting the specifications for generator Underfrequency setpoints in order to maintain a viable UFLS Program. For sub-regions where a large percentage of the total generation fleet is comprised of individual units < 20 MVA and connected to buses < 100 kV, the contribution of these units to the overall success of the sub-regions UFLS Program are more pronounced. It is suggested that the threshold should be established by refering to the requirements of the Region or as established by the Reliability Coordinator (sub-region). As an alternative, it is suggested that all generating units operating in a Reliability Coordinators' or RTO/ISO's market system, regardless of size, shall follow this Standard based on their materiality to the reliability of the bulk power system.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. Extending the applicability to units beyond those covered under the Registry Criteria would make those units subject to all Generator Owner requirements in all other Standards.		
New York Independent System	No	The interconnection Voltage is not relevant, only the amount of generation potentially lost to the system.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>Operator</td><td></td><td></td></tr>
<tr><td colspan="3">Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. Extending the applicability to units beyond those covered under the Registry Criteria would make those units subject to all Generator Owner requirements in all other Standards.</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No</td><td>In an islanded situation, each generator's status is critical to ensuring frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not holding the smaller generators subject to the requirements associated with generator frequency tripping exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. Extending the applicability to units beyond those covered under the Registry Criteria would make those units subject to all Generator Owner requirements in all other Standards.</td></tr>
<tr><td>Converteam Naval Systems Inc.</td><td>No</td><td></td></tr>
<tr><td>Indiana Municipal Power Agency</td><td>Yes</td><td>A single unit not meeting these thresholds (an unregistered unit) can always be registered if a technical justification is given and proven. However, this does not mean a "blanket" registration can apply to all units (unregistered units) that do not meet these thresholds.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT agrees with your position. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria.</td></tr>
<tr><td>American Electric Power</td><td>Yes</td><td>The applicability appears to be from the NERC Compliance registry. This is probably okay for the requirement on voltage related tripping, but the impact of frequency related tripping is not restricted to the BES as it likely would be with voltage tripping. A separate single-size applicability, independent of BES/non-BES connection, may be more appropriate for the frequency tripping requirement.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. Extending the applicability to units beyond those covered under the Registry Criteria would make those units subject to all Generator Owner requirements in all other Standards.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
SERC Dynamics Review Subcommittee (DRS)	Yes	All generating units with the given thresholds are registered in the NERC compliance registry. We believe that these units should adhere to the requirements in the Standard. Each system reacts differently to the loss of different sizes of generators. This Standard, which is applicable to every registered entity, should cover these situations. Hence, the given thresholds, though restrictive, are adequate.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria.		
Ameren	Yes	Again from our perspective, the main objective is allow UFLS/UVLS to do their job to arrest frequency/voltage decline and retain generation on-line so as not to exacerabate the extreme disturbance. Of course, generation equipment limits must be respected. This standard should not encourage GO to augment protection or become more conservative than warranted, possibly refuting the main objective. We formerly belonged to the now defunct MAIN region. Previous MAIN requirements for generators were: Generator UF Setting (Hz) Minimum Time Delay (Sec)> 59.5 Hz Automatic tripping not permitted< 59.5 to > 59.2 Hz 2700 seconds< 59.2 to > 58.5 Hz 120 seconds< 58.5 to > 58.0 Hz 15 seconds< 58.0 Hz Owner's Discretion We have applied these to generation that has connected in the last decade unless the GO had manufacturer recommendations to the contrary.
Response: Thank you for your comment. The SDT agrees that generation equipment limits must be respected and allows exemption for documented technical limitations in Requirement R3. A phrase has been added to R1 and R2 indicating that frequency and voltage protective relaying is not required. The Frequency vs. Time curves in Attachment 1 are designed to coordinate with the curves being used by the NERC Underfrequency Load Shedding (UFLS) Standard Drafting Team.		
US Bureau of Reclamation	Yes	The threshold should be consistent with the NERC Reliability Compliance Registry Criteria.
Response: Thank you for your comments. The SDT agrees with your position. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria.		
Progress Energy, Inc.	Yes	All generator units with the given thresholds are registered in the NERC compliance registry. We consider that such units should adhere to the requirements in the standard. Each system reacts differently to the loss of different sizes of generators. This standard, which is applicable to every entity, should cover all such situations. Hence, the given thresholds, though restrictive, are adequate.
Response: Thank you for your comments. The SDT agrees with your position. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria.		

Organization	Yes or No	Question 5 Comment
Old Dominion Electric Cooperative	Yes	This is the NERC/FREC set levels, all units with this scope should have to comply with the standard. Units that are not within the above criteria should be exempt from it as they are not aware, possible to provide their input.
Response: Thank you for your comments. The SDT agrees with your position. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria.		
Consumers Energy Company	Yes	We believe this is sufficient to address the concern if this picks up the wind farms that are a growing part of generating capacity.
Response: Thank you for your comments. After consideration of comments and discussion with NERC staff, the SDT has assigned the applicability to Generator Owners as described in the Compliance Registry Criteria. The SDT feels most wind farms are registered due to their aggregate size and Point of Interconnection voltage.		
FirstEnergy	Yes	
Luminant Power	Yes	
AWEA	Yes	
Gainesville Regional Utilities	Yes	
American Wind Energy Association	Yes	
Southern California Edison Company	Yes	
Brazos Electric Power Cooperative	Yes	
Lakeland Electric	Yes	

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	Yes	
Kansas City Power & Light	Yes	
Entergy Fossil Operations	Yes	
PJM Interconnection	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Duke Energy	Yes	
American Transmission Company	Yes	

6. The SDT proposed a set of VRFs based on size delineation of units. Do you agree with this approach? Do you agree with the MVA levels? If you disagree with either the approach or the MVA levels, please explain in the comment area.

Summary Consideration:

There was no consensus on this issue.

The major comment issues raised are:

- There should be only a single VRF Different MVA break points or methodologies (MWh, percent of units, impact-based)

The GV SDT consideration for the major comment issues is:

- After consideration of comments and discussion with NERC staff, the SDT agrees with the minority position that a single VRF must be used for each Requirement. NERC Standard Processes Manual does not allow multiple VRFs for a Requirement regardless of the methodology used to separate them.

Organization	Yes or No	Question 6 Comment
Dominion	No I disagree with the approach	All generators identified in a transmission owner's restoration plan warrant a high VRF. Additionally, generators 500 MVA warrant a high, generators > 100 MVA but < 500 MVA warrant a medium and generators 100 MVA warranty a low VRF
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		
Northeast Power Coordinating Council	No I disagree with the approach	Both bullets should be checked above (form will not accept).
Response: Thank you for your comments. The nature of the disagreement is not understood.		
SERC Dynamics Review Subcommittee	No I disagree with	It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH. Consider the example where a plant consists of numerous medium sized (100-200 MVA) units with a common relay setting error.

Organization	Yes or No	Question 6 Comment
(DRS)	the approach	Even though the individual units are relatively small, there is a potentially large impact when the whole plant is considered.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		
IRC Standards Review Committee	No I disagree with the approach	Size dependent VRFs do not reflect the potential reliability risk associated with more than one Medium size generating unit (>100 MVA and <500 MVA) failing to comply with the standard. Two of such units at, say, 400 MVA each, that trip unnecessarily will have a greater collective impact on the island frequency than the tripping of a 500 MVA unit.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		
Veolia Environmental Services	No I disagree with the approach	The delineation should be based on actual or potential impact to the BES of a unit tripping as determined by the BA and TOP modeling.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria. A VRF cannot be modified by BA's and TOP's on a case-by-case basis.		
Old Dominion Electric Cooperative	No I disagree with the approach	I assume this was because the bigger units have a bigger impact on reliability than the smaller units. I am fine with this approach, but might have a minor comment on the break levels.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		
Basin Electric Power Cooperative	No I disagree with the approach	This may be appropriate but I have not seen the supporting technical report so I cannot say that I agree. This is likely to be something that has to be applied on a case-by-case basis, with consideration given to how many units would be excluded in some geographic area. There is some latitude to make exceptions, but in the future, we may have many more units that fit this category, and then this exclusion becomes a big issue.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRF's) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5), These VRF's were developed using NERC's VRF Criteria. Exceptions to Requirements R1 and R2 are only allowed for documented technical limitations (e.g. OEM documents indicating that operation within these requirements will damage the equipment).</td></tr>
<tr><td>Progress Energy, Inc.</td><td>No I disagree with the approach</td><td>It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH. Consider the example where a plant consists of numerous medium (100-200 MVA) units with a common relay setting error. WECC have relatively small units, but potentially large impact when the whole plant is affected.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT agrees that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5).</td></tr>
<tr><td>Hydro-Québec TransEnergie (HQT)</td><td>No I disagree with the approach</td><td>Given the potential impact on survivability of an island, and the need to lower the unit capacity thresholds for which this standard is applicable, as recommended in the comment to Question 5, it is suggested that the folowing Violation Risk Factor thresholds be applied:High > 100 MVAMedium > 20 MVA and < 100 MVA Lower < 20 MVA Given the potential impact on survivability of an island, and the recommendation in our response to Question 5 to lower the unit capacity thresholds for which this standard is applicable, we recommend the following Violation Risk Factor thresholds:High >100 MVAMedium > 20 MVA and 100 MVALower 20 MVA</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.</td></tr>
<tr><td>Duke Energy</td><td>No I disagree with the approach</td><td>It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT agrees that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5).</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No I disagree with the approach</td><td>Size dependent VRFs do not reflect the potential reliability risk associated with more than one Medium size generating unit (>100 MVA and <500 MVA) failing to comply with the standard. Two of such units at, say, 400 MVA each, that trip unnecessarily will have a greater collective impact on the island frequency than the tripping of a 500 MVA unit.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT agrees that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5).		
Ameren	No I disagree with the approach	Are they based on the individual unit or the aggregate at the Point of Interconnection? Average annual production (MWh) is a better indicator of their threat to the BES during UF or UV events. Larger units should not be penalized just because they are large. If large and generating many MWh then they're big and likely to be on-line for an event.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		
US Bureau of Reclamation	No I disagree with the approach	If this approach is appropriate for this standard, it seems this approach should be used for all Standards applicable to generators.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		
Constellation Power Generation & Constellation Nuclear	No I disagree with the approach	
FirstEnergy	Yes I agree with the approach	A suggestion for SDT's consideration is that VRFs could be based on percentage of units not in compliance. A utility may have several large units (high VRF) and many small (low VRF) not in compliance.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		
Lakeland Electric	Yes I agree with the approach	The VRF levels should range from low to high based on unit size and how the unit size impacts BES.
Response: Thank you for your comments. Based on industry comment and conversation with NERC Staff, the SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level is assigned for R1, R2, and a new performance requirement (R5). These VRFs were developed using NERC's VRF Criteria.		

Organization	Yes or No	Question 6 Comment
Entergy Fossil Operations	Yes I agree with the approach	
PJM Interconnection	Yes I agree with the approach	
Kansas City Power & Light	Yes I agree with the approach	
MRO NERC Standards Review Subcommittee	Yes I agree with the approach	
Luminant Power	Yes I agree with the approach	
Southern Company	Yes I agree with the approach	
Converteam Naval Systems Inc.	Yes I agree with the approach	
Consumers Energy Company	Yes I agree with the approach	
E.ON U.S.	Yes I agree with the approach	
AWEA	Yes I agree with the approach	
Gainesville Regional Utilities	Yes I agree with the approach	
American Wind Energy Association	Yes I agree with the approach	

Organization	Yes or No	Question 6 Comment
Southern California Edison Company	Yes I agree with the approach	
Brazos Electric Power Cooperative	Yes I agree with the approach	
Manitoba Hydro	Yes I agree with the approach	
NIPSCo	Yes I agree with the approach	
Indiana Municipal Power Agency	Yes I agree with the approach	
Northeast Utilities	Yes I agree with the approach	
American Electric Power	Yes I agree with the approach	
New York Independent System Operator	Yes I agree with the approach	
American Transmission Company	Yes I agree with the approach	

6.1 Do you agree with the MVA levels?

Summary Consideration:

There was no consensus on this issue.

The major comment issues raised are:

- There should be only a single VRF
- Lower MVA break points should be used

The GV SDT consideration for the major comment issues is:

- As discussed in the Summary Consideration to Question 6, multiple VRFs for a Requirement are not allowed, so the responses to this question is no longer applicable. The SDT developed a single VRF for Requirements R1 and R2 based on the NERC VRF Criteria.

Organization	Yes or No	Question 6.1 Comment
Northeast Power Coordinating Council	No	Both bullets should be checked above (form will not accept).Given the potential impact on survivability of an island, and the need to lower the unit capacity thresholds for which this standard is applicable, as recommended in the comment to Question 5, it is suggested that the folowing Violation Risk Factor thresholds be applied:High > 100 MVAMedium > 20 MVA and < 100 MVA Lower < 20 MVA Given the potential impact on survivability of an island, and the recommendation in our response to Question 5 to lower the unit capacity thresholds for which this standard is applicable, we recommend the following Violation Risk Factor thresholds:High >100 MVAMedium > 20 MVA and 100 MVALower 20 MVA
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
SERC Dynamics Review Subcommittee (DRS)	No	There should not be levels
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		

Organization	Yes or No	Question 6.1 Comment
Kansas City Power & Light	No	What is the basis for the MVA levels proposed by the standard here?
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5). The SDT did not have a technical basis for assigning a given level, and was asking stakeholders for assistance.		
IRC Standards Review Committee	No	Please see above comments. We suggest that the same VRFs apply to all units that meet the Applicability criteria.
Response: Thank you for your comments. The SDT agrees that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
Southern Company	No	The VRF levels should range from low to high based on size of unit. Low risk 100-200MVA. Medium risk 200-500 MVA. High risk >500MVA.
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
Gainesville Regional Utilities	No	I believe that > than 100 mva should only be included
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
Veolia Environmental Services	No	Size should not be a factor, only practical impact to the BES.
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
Basin Electric Power Cooperative	No	see above comment
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement, the Violation Severity Levels (VSLs) will be delineated by a Generator Owner's cumulative capacity (nameplate MVA) that did not meet the defined requirements.		
Progress Energy, Inc.	No	There should not be levels.

Organization	Yes or No	Question 6.1 Comment
Response: Thank you for your comments. The SDT agrees that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
Hydro-Québec TransEnergie (HQT)	No	Given the potential impact on survivability of an island, and the need to lower the unit capacity thresholds for which this standard is applicable, as recommended in the comment to Question 5, it is suggested that the folowing Violation Risk Factor thresholds be applied: High > 100 MVA Medium > 20 MVA and < 100 MVA Lower < 20 MVA Given the potential impact on survivability of an island, and the recommendation in our response to Question 5 to lower the unit capacity thresholds for which this standard is applicable, we recommend the following Violation Risk Factor thresholds: High >100 MVA Medium > 20 MVA and 100 MVA Lower 20 MVA
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
American Electric Power	No	The MVA levels appear to be arbitrary. What is the basis that the SDT used to establish these MVA thresholds?
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5). The SDT did not have a technical basis for assigning a given level, and was asking stakeholders for assistance.		
Duke Energy	No	It is the aggregate impact of all an entity's units that matters. There should be only one VRF - HIGH.
Response: Thank you for your comments. The SDT agrees that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
Independent Electricity System Operator	No	Please see above comments. We suggest that the same VRFs apply to all units that meet the Applicability criteria.
Response: Thank you for your comments. The SDT agrees that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5)..		
Ameren	No	See above
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		

Organization	Yes or No	Question 6.1 Comment
Constellation Power Generation & Constellation Nuclear	No	
Old Dominion Electric Cooperative	Yes	Might have a minor tweak in the future.
Response: Thank you for your comments. The SDT has determined that a single VRF is more appropriate. As such, the Violation Risk Factors (VRFs) no longer are delineated by MVA level. Instead, a single VRF level will be assigned and for R1, R2, and a new performance requirement (R5).		
Luminant Power	Yes	
Entergy Fossil Operations	Yes	
PJM Interconnection	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	
FirstEnergy	Yes	
Converteam Naval Systems Inc.	Yes	
Consumers Energy Company	Yes	
E.ON U.S.	Yes	
AWEA	Yes	
American Wind Energy Association	Yes	
Southern California Edison Company	Yes	

Organization	Yes or No	Question 6.1 Comment
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
NIPSCo	Yes	
New York Independent System Operator	Yes	
American Transmission Company	Yes	

7. If you are aware of any regional variances that would be required as a result of this standard please identify the regional variance here.

Summary Consideration:

Most responders, knew of no required regional variances, several commented on the potential need for variances. .

The issues associated with the majority of the comments received are:

1. There are some regional geographical differences.
2. There is concern about UFLS standards that are being developed in the various regions pending the conclusion of UF studies. These study results may indicate the need for regional variances.

Some other comment issues are:

1. One commenter suggests the SDT wait for the regions to complete their UF studies before going forward with PRC-024.
2. One commenter indicates that FRCC has suspended development of the regional version of PRC-024.
3. Certain regional UFLS drafts include requirements for non-conforming generators to acquire “load-shed” service. These drafts do not identify the GO/GOP in the applicability section, and it is not certain that any entity can offer a “load-shed” service.

The GV SDT considerations for these issues are:

The SDT is aware that some regions have stopped developing their Standards because of the efforts at NERC to develop similar continent-wide standards**.**

The SDT notes that the NERC Standard Processes manual, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32) fhas provisions for entities to submit a request for a variance. However, Regional Standards will need to be addressed at the regional level unless the region desires to seek a variance through the NERC Standard Development Process.

Organization	Question 7 Regional Variance
NERC System Protection and Control	The FRCC UFLS has a requirement for generators to remain on line for 1 second with frequency down to 57.5 Hz.

Organization	Question 7 Regional Variance
Subcommittee (SPCS)	Regional differences are developing as the Regions perform studies to current UFLS strategies while considering the coordination requirements of generator underfrequency tripping. To date, NPCC and FRCC may be the only regions that have completed their studies. It is recommended that PRC- 024-1 wait on going forward in the standards process until the regions conclude their studies and develop their requirements based on their particular portions of the interconnected power system.
Response: The SDT thanks you for your comments. The SDT is aware that some regions have stopped developing their Standards because of the efforts at NERC to develop similar Standards. Therefore, it may not be practical to wait to develop NERC Standards until the regions have concluded their respective studies. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 ((http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32) has provisions for the Regions to submit a request for a Variance.	
Dominion	We are not aware of any. However, we are aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service. We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicted upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service.
Response: The SDT thanks you for your comments. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32)has provisions for the regions to submit a request for a variance. However, Regional Standards will need to be addressed at the regional level unless the region desires to seek a regional through the NERC Standard Development Process.	
Northeast Power Coordinating Council	We are aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service. We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicated upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service. The Quebec Interconnection, within the Eastern Interconnection, would need different settings from the ones listed in Attachment 1 to coordinate with its UFLS program.
Response: The SDT thanks you for your comments. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32)has provisions for the regions to submit a request for a variance. However, Regional Standards will need to be addressed at the regional level unless the region desires to seek a variance through the NERC Standard Development Process.	

Organization	Question 7 Regional Variance
Kansas City Power & Light	Not aware of any regional differences.
Response: The SDT thanks you for your comments.	
MRO NERC Standards Review Subcommittee	If a region has performed a detailed system study of the Under Frequency protection systems in their region and developed protective settings based off the characteristics developed in the study, the region should be allowed to deviate from the Generator Protection curve in Attachment 1.
Response: The SDT thanks you for your comments. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32)has provisions for the regions to submit a request for a variance.	
Constellation Power Generation & Constellation Nuclear	We are not aware of any. However, we are aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service. We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicted upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service.
Response: The SDT thanks you for your comments. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32) has provisions for the regions to submit a request for a variance. However, Regional Standards will need to be addressed at the regional level unless the region desires to seek a variance through the NERC Standard Development Process.	
Progress Energy, Inc.	No. FRCC has suspended work on a regional version of PRC-024. The regional version will have to reviewed and compared to the NERC standard once developed.
Response: The SDT thanks you for your comments. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32) has provisions for the regions to submit a request for a variance, should the regions decide to do so.	
Basin Electric Power Cooperative	See the detailed answer provided to question 2. It covers the need for regional variance.
Response: The SDT thanks you for your comments.	

Organization	Question 7 Regional Variance
Hydro-Québec TransEnergie (HQT)	Yes, the Quebec Interconnection, within the Eastern Interconnection, would need different settings than the ones depicted in the Attachment 1 to coordinate with its UFLS program.We are also aware that a number of regions have draft UFLS standards that apply to generators despite the fact NERC Reliability Standards PRC-007, PRC-008 and PRC-009 do not contain either GO or GOP in the applicability section. These regional drafts contain provisions that require non-conforming generators to acquire 'load shed' service. We have repeatedly cited our inability to find any entity that would offer such service as well as technical difficulties in developing a UFLS predicted upon such a service. Despite our comments, the latest drafts continue to require non-conforming generators to acquire 'load shed' service.
Response: The SDT thanks you for your comments. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32) has provisions for the Regions to submit a request for a Variance. However, Regional Standards will need to be addressed at the Regional Level unless the Region desires to seek a Variance through the NERC Standard Development Process.	
Ameren	It seems that geography (e.g. peninsulas, coastal areas) and load sparcity, and dense load served by distant generation have been significant factors in blackout events. As such, regional differences do exist.
Response: The SDT thanks you for your comments. The NERC Reliability Standards Development Procedure, approved by FERC on September 3, 2010 (http://www.nerc.com/docs/standards/sar/Appendix_3A_Standard_Processes_Manual_20100903_2_.pdf, see page 32) has provisions for the regions to submit a request for a variance, should the region decide to do so.	
IRC Standards Review Committee	None
Luminant Power	NA
Southern Company	No.
Consumers Energy Company	No.
Old Dominion Electric Cooperative	No.
Lakeland Electric	No
Manitoba Hydro	none
American Electric Power	No known regional variances

Organization	Question 7 Regional Variance
Duke Energy	None
Independent Electricity System Operator	None

8. If you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify the conflict here.

Summary Consideration:

There were several commenters who stated they were aware of agreements between some generators and their respective Transmission Owners that contain frequency coordination requirements that differ from those in Table 1. The SDT answered this concern with: “The Generator Verification SDT has worked closely with the UFLS SDT to insure coordination of this Standard with the UFLS Standard. When the UFLS standard is approved and in effect entities will be required to comply. The SDT believes the drafted standard allows for exceptions due to technical limitations per Requirement R5 (R3 in the revised standard). Several commenters gave concerns that Nuclear Plant Requirements may conflict. The SDT answered this concern with: “The SDT is aware that Nuclear Plant licensing issues may not allow a generator to meet the requirements of this Standard and this might be an acceptable basis for exclusion. However, the Nuclear Power Plant owner would be expected to review these limitations and assure that a less restrictive set-point is not possible.

Organization	Question 8 Conflict
Dominion	Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.
Response: Thank you for your comments to this question. The Generator Verification SDT has worked closely with the UFLS SDT to insure coordination of this Standard with the UFLS standard. When the UFLS Standard is approved and in effect entities will be required to comply. The SDT believes the drafted Standard allows for exceptions due to technical limitations per Requirement R5 (R3 in the revised standard).	
Northeast Power Coordinating Council	Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.
Response: Thank you for your comments to this question. The Generator Verification SDT has worked closely with the UFLS SDT to insure coordination of this Standard with the UFLS Standard. When the UFLS standard is approved and in effect entities will be required to comply. The SDT believes the drafted Standard allows for exceptions due to technical limitations per Requirement R5 (R3 in the revised standard).	
FirstEnergy	This standard may need to be coordinated with current efforts to revise standard PRC-006-1, and with the Regional

Organization	Question 8 Conflict
	standards being developed for UFLS, such as RFC's PRC-006-RFC-01.
Response: Thank you for your comments. The SDT has worked closely with the NERC UFLS team to ensure a coordinated effort is being conducted.	
Constellation Power Generation & Constellation Nuclear	Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.
Response: Thank you for your comments. The Generator Verification SDT has worked closely with the UFLS SDT to insure coordination of this Standard with the UFLS Standard. When the UFLS standard is approved and in effect entities will be required to comply. The SDT believes the drafted Standard allows for exceptions due to technical limitations per Requirement R5 (R3 in the revised standard).	
Southern Company	Nuclear Plant Requirements may conflict.
Response: Thank you for your comments. The SDT is aware that Nuclear Plant licensing issues may not allow a generator to meet the requirements of this Standard and this might be an acceptable basis for an exclusion. The Nuclear Power Plant owner would be expected to review these limitations and assure that a less restrictive set-point is not possible that would permit coordination with this Standard while still protecting the nuclear plant. The SDT will discuss and investigate the inclusion of this concern in R5 (R3 in the revised standard).	
Basin Electric Power Cooperative	The proposed generation off-nominal frequency criteria conflicts with the MRO UFLS program, and will not work for programs that need to shed more than 30% of system load. Technically this is not a conflict with regulatory functions, rule order, tariff, rate schedule, legislative requirement or agreement; but it is a conflict with our efforts to design an appropriate load shedding program for the MRO region.
Response: Thank you for your comments. The SDT has worked closely with the NERC UFLS team to ensure a coordinated effort is being conducted.	
Progress Energy, Inc.	Yes, if the standard is extended to other plant equipment NRC nuclear plant licenses will be in conflict.
Response: Thank you for your comments to this question. The SDT is aware of these concerns.	
Hydro-Québec TransEnergie (HQT)	Yes. We are aware of agreements between some generators and their respective transmission owners that contain frequency coordination requirements that differ from those in Table 1, and that, in some cases, the transmission facility(ies) that connects the generator to the BES has underfrequency tripping that would operate prior to the levels shown in Table 1, thus negating any modification that a generator might make to conform. We suggest that this

Organization	Question 8 Conflict
	standard also exempt these GOs from meeting R1 and R2 and that R5 be modified to allow for such exception.
Response: Thank you for your comments to this question. The Generator Verification SDT has worked closely with the UFLS SDT to insure coordination of this sSandard with the UFLS Standard. When the UFLS Standard is approved and in effect entities will be required to comply. The SDT believes the drafted Standard allows for exceptions due to technical limitations per Requirement R5 (R3 in the revised standard).	
Ameren	Nuclear Plant Requirements may conflict.Footnote 2 refers to the agreements for which the GO is not responsible. Also, grandfathered generation of more vertically integrated entities and/or in certain states may not have such formal agreements.
Response: Thank you for your comments to this question. The SDT is aware that Nuclear Plant licensing issues may not allow a generator to meet the requirements of this Standard and this might be an acceptable basis for an exclusion. The SDT will discuss and investigate the inclusion of this concern in R5. The SDT disagrees with the comment referencing footnote 2, and believes the GO (Generator Owner) is responsible for these actions.	
First Solar	The requirements are inconsistent with UL 1741 and IEEE 1547 as applied to existing solar PV inverter design. Compliance withn the proposed Standard would require an industry re-design and recognition from the Interconnecting Transmission Owner that projects would not meet these other standards. Additionally the Standard should provide for a phase in period for inverter based PV facilities so that such redesign can be accommodated.
Response: The standard criteria are applicable to voltage on the BES. The UL and IEEE standards will likely need to be considered if a plant performance Standard were to be developed.	
Kansas City Power & Light	Not aware of any conflicts.
MRO NERC Standards Review Subcommittee	No known conflict at this time.
IRC Standards Review Committee	None
Luminant Power	NA
Consumers Energy Company	No.
Old Dominion Electric Cooperative	No.
Lakeland Electric	No

Organization	Question 8 Conflict
Manitoba Hydro	none
American Electric Power	No known conflicts
Duke Energy	None
Independent Electricity System Operator	None

9. Are there other improvements that the SDT should consider for this revision of PRC-024-1 that you haven't already identified in response to other questions? If yes, please provide in the comment area.

Summary Consideration:

There were many different suggestions to improve upon the proposed Standard. They are summarized as follows:

- The Standard should only apply asynchronous generators.
- The Standard could lead to relays being activated needlessly.
- The Standard should apply at the generator terminals, not the POI.
- Consider other UFLS Standards activities.
- Consider over frequency setting at 63 hertz.
- Do not trip on under voltage.
- Provide additional technical detail.
- Provide clarity on relay settings.
- Clarify language.
- Concerns with generator damage, Standard exemptions, and who approves them.
- Steady state versus dynamic simulation.
- Implementation schedule concerns.
- Concerns over who reports what to whom.
- Transient vs. steady state applicability.
- Regional vs. NERC requirements.
- Reactive power requirements.

Organization	Yes or No	Question 9 Comment
Entergy Fossil Operations	Yes	Do away with this standard.

Organization	Yes or No	Question 9 Comment
Response: Thank you for comment. This Standard is an extension of work done in Phase III/IV and is deemed of value.		
NERC System Protection and Control Subcommittee (SPCS)	Yes	PRC-024 should only apply to non-synchronous machines. Coordination of synchronous generator voltage and frequency protective relay settings with transmission protection systems should be addressed along with all other coordination in PRC-001 Protection coordination. SPCS is preparing a Technical Reference paper on such coordination that is expected to be completed in June, 2009. Generator voltage and frequency protective relays are included in that that paper. The Attachment 2 voltage ride through curve was developed, to SPCS understanding, by compiling a number of system events delineating those events whereby the tripping of generators would exacerbate the event. It does not appear that the SDT analyzed data from the August 14, 2003 Northeast Blackout. Actual data from the event in Michigan, before the system cascaded and broke apart revealed 345 kV system voltages of less than 0.9 per unit. Some generators in Michigan tripped by undervoltage relays set at 0.9 per unit that significantly accelerated the cascade. Even those generators along the western fringe of the soon-to-be separated power system were of event more concern; data indicated these large units were experiencing 345-kV voltages of less than 0.9 per unit. Those generators did not trip because they did not have undervoltage relaying set to trip. Had these units tripped on undervoltage relaying, the event would have extended much further to the west of the actual impacted area. The Standard requires generator relays to be set based on a voltage at the interconnection point to the BES. However the relays are typically connected to a voltage source at the generator, not the BES interconnection. The translation from generator terminal voltage to a point of interconnection voltage is not a direct relationship. It will vary depending upon the assumption made for generator real and reactive output, or the distance to the point of interconnection. The Standard gives no direction regarding these assumptions. The voltage to be sensed must be the generator terminal voltage. IEEE C50.13 describes the standards to which the modern generators were built. This standard recommends reducing unit output after ascertaining the presence of an undervoltage alarm. This standard does not recommend unit tripping. Totally different relay settings will be obtained with different generator output assumptions. This lack of consistency will make it impossible to determine if compliance to the Standard is achieved. SPCS also have concerns with the overfrequency curve in Attachment 1 in light of the August 14, 2003 Northeast Cascade and Blackout. During the sequence of events an island formed consisting of portions of western New York and eastern Ontario with a significant generation-load mismatch. The surplus generation in the island resulted in an overfrequency condition to which several large generating units responded to arrest the overfrequency at 63 Hz. Had those units been set to trip on the proposed curve on August 14, the units would have tripped prematurely potentially leading to a collapse of the island. While the overfrequency curve may be acceptable as a floor for setting the overfrequency relays, there should also be a requirement to coordinate the overfrequency tripping with the unit controls and unit capability to maximize the ability of machines to control overfrequency while operating within their capability. Undervoltage alarms as experienced by hydro, fossil, combustion, and nuclear units are an indicator of possible thermal issues within the generator. Other alarms from RTDs and hydrogen pressure are better indicators. Manufacturers recommend operator action up to and including reduction in unit output rather than a unit trip. Tripping units on undervoltage is not recommended by the IEEE C37.102 standard on generator protection. Rather C37.102 also recommends alarm. Each type of unit, hydro, fossil, nuclear, combustion, and renewable generator have different thermal issues relating to system undervoltage. A single curve over-simplifies the issue to the point that system reliability is degraded. If any curve is included, it should be focused only on wind turbines as they have voltage ride through controls. Attachment 2 requires voltage evaluation at the system voltage level. Concerning Attachment 1, SPCS believes this is mainly present to insure that generator tripping will not interfere with UFLS programs. There should be a

Organization	Yes or No	Question 9 Comment
		statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." SPCS suggests that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs. The SDT has not described how the curve was compiled. Technical committees within the IEEE went to great lengths to describe the turbine blading off-frequency limitation curves. Every manufacturer submitted their curve and a family of curves was created that showed distinct curves for each manufacturer. The NERC 1978 document, "Underfrequency and Undervoltage Relay Applications Large Turbine Generators included a collection of individual manufacturer which when plotted together provided a prospective on the widely varying limits of the various turbines. There is a danger of misinterpretation to use one curve. In PRC-024-1 there was no description stating how the curve was developed. If a machine is not at risk and if a UFLS simulation shows that the bottom frequency will occur outside of the "one size fits all curve" then there should be a provision to use the manufacturer's curve rather than shed more load just to fit the attachment 1 curve.A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed relaying not to trip during" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and Voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer. Concerning A.R1.2 and Attachment 1, the language refers to a “no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. SPCS would suggest that setting directly on the curves should be permitted. For example, if 1.0 seconds at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 seconds at 57.79 Hz. SPCS suggests "Setting directly on the curves is permitted, and settings outside the curves are permitted." Concerning A.R2, this Standard addresses setting of Voltage relays based on Voltage at the point of interconnection, which is not directly translatable to Voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard. Simply setting the generator protection relay at 0.90 per unit may, in fact, be an incorrect setting to achieve the desired performance. Settings must include allowances for all equipment tolerances: voltage transformer errors, relay tolerances, and testing instrumentation errors. The actual setting needed to account for such variances may require that the relay be actually set to trip at 0.84 or 0.86, or some other seemingly conflicting value, in order to achieve the goal of not tripping at 0.90 per unit.

Response: Thank you for your comment. The SDT has captured what we believe are the main points of your comment s and has provided responses below:

- **Apply only to asynchronous generators (synchronous gen goes to PRC-001) –** The SDT has taken the direction to develop a Standard that is technology neutral. PRC-001 currently addresses communication coordination review but not relay setting or generator performance specifically.
- **The Standard could lead to relays being activated needlessly –** The SDT agrees and has modified the proposed Standard to emphasize this point. If the GO has this relay equipment installed and has chosen to trip the generator with it, then the settings shall be determined in accordance with this Standard.

Organization	Yes or No	Question 9 Comment
• **POI issue –** The SDT has provided additional assumptions for the calculation of relay settings on the basis of the voltage as measured at the POI. It is provided in Attachment 2 of the revised Standard. The SDT specifically chose the point of interconnection because that is where the faults that this standard is intended to address occur. • **Over frequency setting at 63 hertz –** The SDT selected 62.5 hertz as a compromise level to account for the majority of generators installed in the system. This Standard does not require generators to set over-frequency relays. • **Alarm and not trip on under-Voltage –** The proposed Standard does not compel GOs to have or set under-voltage relays to trip generators. The SDT believes it would be inappropriate to prohibit the protection of the generator through the setting of protective relays. • **Include provision that UFLS shall not be interfered with –** At the recommendation of FERC and NERC, the SDT has coordinated the UF relay curve with the NERC UFLS SDT members' input. • **Delay this Standard until regional UFLS work is completed –** See above. The UFLS standard has been approved by stakeholders. • **Want more technical detail on development of curves –** A WECC white paper formed the basis of the development of the curves for this Standard, along with additional data from SERC, Xcel Energy, AWEA, GE and AREVA. This information is available upon request. • **Seek clarity regarding setting on the line or anywhere up to line –** We agree and the Standard was modified to provide improved clarity. • **Specify relay settings that account for various equipment tolerances –** There is room between the manufacturer capability curves and the settings limits curves that allows relays to be set to accommodate tolerances.		
PJM Interconnection	Yes	In R2.2.1, replace -greater- with -faster- or -slower-, whichever is correct. In R2.2.3 replace -intended- with -required-. In R4, replace -written- with -documented-. In R5, add an -s- to -System- in the parentheses. In R3, R4 and R5 - Concerned with the GO responsibility to send to their RC, PC, TO and TP. Would rather see the GO responsibility be to just to respond to any RC, PC, TO and TP requests.
Response: Thank you for your comment. The SDT has modified the Standard to address the language concerns. The SDT prefers the choice of "written" as opposed to "documented" in R4. The term "Protection System" is a defined NERC Glossary term. In R3 and R5 all the named entities must receive the information. In R4 we agree that only the requesting entity must receive the information.		
Dominion	Yes	We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that "For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected" We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system under voltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator (2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations? If the standard is intended to apply to volts per hertz

Organization	Yes or No	Question 9 Comment
		relays, suggest: 1. Revising footnote 1 to specifically include volts per hertz relays. 2. Revise Steps 4.2.1 and 4.2.2 to specifically include volts per hertz relays. 3. That the standard should incorporate specific guidance for facilities using volts per hertz logics and include a graph showing the voltage and frequency excursions in terms of volts per hertz.
Response: Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions, addressing the auxiliary systems concern. With respect to steady state evaluations versus dynamic simulations, the Standard does not preclude the application of either. The SDT agrees and has added volts per hertz relays among the listed items in footnote 1.		
Northeast Power Coordinating Council	Yes	Referencing R5 and R6 of the Standard: The Reliability Coordinator should be give veto power over exceptions to the requirements herein. Should the Generator Owner/Operator not be able to, or be unwilling to, make changes to setpoints to come into compliance with this Standard, the Reliability Coordinator should be given the authority to invoke required mitigation, such as requiring the Generator Owner/Operator to contract for compensatory load shedding up to the total amount of MW of each generating unit that fails to comply with the required setpoints. In addition, The "Off-Nominal Frequency Capability Curve" in Attachment 1 does not coordinate with the underfrequency load shedding (UFLS) program design parameters proposed by the NERC Underfrequency Load Shedding Standard Drafting Team for Project 2007-01. The misccoordination occurs in the time range approximately between 5 and 10 seconds. This miscoordination can be eliminated by extending the horizontal line at 57.8 Hz to 5 seconds and revising the diagonal line to have endpoints at 57.8 Hz/5s and 59.5 Hz/1800s. This modification will provide coordination with the UFLS program design parameters while still maintaining coordination with turbine-generator capability. Due to the time scale on the graph in Attachment 2, the curves do not indicate the time at which the transient overvoltage and undervoltage requirements end, at which point the continuous voltage requirements would be applicable. Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above:> Concerning Attachment 1, we believe this is mainly present to infer that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled. > A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed relaying not to trip during" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer.> Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted."> Concerning A.R2, this Standard addresses setting of voltage relays based on voltage at the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td></td><td></td><td>point of interconnection, which is not directly translatable to voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard. We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that "For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected" We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system undervoltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator?(2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations?</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT has captured what we believe are the main points of your comment sand has provided responses below:
RC should have veto power over exemptions – The SDT believes it is the responsibility of the GO to determine the capability of the existing unit. The judgment as to validity of an exemption is a compliance matter.
RC should have authority to decide mitigation, e.g., compensatory load shedding – The SDT believes mitigation of inability to comply with a Standard is a compliance matter.
UFLS mis-coordination – The UFLS SDT and this Standard Drafting Team conferred and resolved the mis-coordination. The resolution that was mutually agreed upon is for the UFLS SDT to modify its Standard to accommodate the frequency curve in this Standard.
PRC-024 should not interfere with UFLS – The two teams have coordinated the frequency curves and strategies.
State that settings shall be determined to prevent machine damage in consultation with manufacturers' recommendation. – The SDT developed the curves in accordance with manufacturer's recommendations and the Standard includes an exemption process for existing generators.
Are settings permitted on the curve? No, settings are not permitted on the curve/line and the Standard has been modified to reflect this more clearly.
POI versus gen terminal – The SDT specifically chose the point of interconnection because that is where the faults that this standard is intended to address occur.
Aux systems relays and Steady state versus dynamic simulation – Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions, addressing the auxiliary systems concern. With respect to steady state evaluations versus dynamic simulations, the Standard does not preclude the application of either. The SDT agrees and has added volts per hertz relays among the listed items in footnote 1.</td></tr>
<tr><td>SERC Dynamics Review Subcommittee (DRS)</td><td>Yes</td><td>1. We recommend deleting the proposed section R2.2.2. If not deleted, change: "meet a shorter voltage ride through" to "meet a less stringent voltage ride through".

2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		provided before they are made in the field. 3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request"
Response: Thank you for your comments. **1. The SDT agrees and has modified the Standard to reflect this.** **2. The SDT intends this requirement to ensure timely notification of equipment changes to the PA and 30 days is a reasonable duration for the Time Horizon of the PA.** **3. The SDT agrees and has modified the Standard to reflect this.**		
Kansas City Power & Light	Yes	Please consider including the Balancing Authority as an entity for the Generator Owner to provide settings information in requirements R3 & R4 since the BA is an entity that has a direct relationship with the operational status of generating stations. R5: Do not agree with the bulleted item where increasing the capability of a generator by 10% is a reason for exemption expiration. As an example, turbine or boiler enhancements can result in greater efficiencies and resulting in an increase of generator capability with no change to the generator or its protection capabilities whatsoever. Recommend removal of this bulleted item. R5: The generator exciter voltage regulator contains protective relay settings such as Volts/Hertz, undervoltage, overvoltage, underfrequency that will also trip the Unit. Is the exciter voltage regulator considered to be part of the generator protective relay system? If so, would a limitation of the exciter voltage regulator be allowed as an exception to the standard or, since the protective system is excluded, would R5 mandate that the exciter voltage regulator be replaced to remove the exception? This issue should be clarified in R5.
Response: The SDT does not observe a reliability need to provide these setting data to the Balancing Authority. **The SDT intends for a GO that decides to increase capability of its unit by a significant amount (now 10%) to also address the technical limitation cited in its exemption.** **The NERC Glossary definition of Protective System does not appear to include voltage regulator. However the SDT intends this Standard to include exciter voltage regulator functions and relays that directly trip the generator based on frequency and voltage excursions.**		
MRO NERC Standards Review Subcommittee	Yes	It would be good to have the option of measuring the voltage at the Generator bus or POI. With the understanding that the voltage must be maintained of the POI.
Response: Thank you for your comment. The SDT agrees that it is the voltage at the POI that must be maintained.		

Organization	Yes or No	Question 9 Comment
FirstEnergy	Yes	1. FE's consensus is that the PRC-024 allowable under-frequency vs. time tripping curve is too tight. By too tight, we mean that the LP turbine buckets and blades are much more tolerant of off freq operation than the proposed tables. Comparing them to the old ECAR curves and allowable tripping times shows they are more stringent. Given how seldom these events occur, (never happened yet in the Eastern Interconnect) expending more of this capacity appears justified. 2. Section A5 Implementation schedule - it may not give sufficient time to implement these requirements. We suggest an additional year as follows: no less than 33% within 2 years of effective date no less than 66% within 3 years of effective date no less than 100% within 4 years of effective date 3. R1.2 Should say off-nominal not off-normal. 4. R2.1 Suggest changing the word "measured" to "experienced". 5. In R5, we suggest changing the first bullet to read: "The equipment causing the limitation is modified, upgraded or replaced with equipment that removes the technical limitation.", and then delete the second bullet. 6. Requirements 3, 4 and 6 specify that the Generator Owner shall provide information to RCs, PCs, TOPs, and TPs that monitor or model the associated unit; however, there is no requirement for these entities to identify themselves to the Generator Owner. How will the Generator Owner know they have identified all of the entities that need the information? 7. In R5, the Generator Owner is granted an exception from requirements R1 or R2 simply by providing documentation of a equipment limitations. There is no independent view of the appropriateness of this exception. The drafting team should consider requiring independent verification of the equipment limitation prior to the granting of an exception to the requirements of the standard. 8. Sec. D References - Is this intended to be part of the standard? If so, it would be helpful if it was linked to the white paper so that we can review it. 9. In Requirements R3 through R6, the SDT may want to consider adding the Transmission Owner as another entity who may need this information. 10. R2.2.1 may need to be re-worded as it requires that protection trip in no greater than 9 cycles. We are not aware of a disadvantage to the system if the tripping takes longer than 9 cycles.

Response:

1. **The SDT intends for GOs to set their relays as tight as possible and not merely on the curve/line.**
2. **The SDT set the timeframe by consensus among team members and the companies they represent. Stakeholder comments have not thus far objected to the implementation schedule. On this basis the SDT is leaving the schedule as proposed.**
3. **The SDT agrees and has made the change.**

Organization	Yes or No	Question 9 Comment
4. The SDT has modified the language in R2. **5. The intent of R5 (now R3 in the revised standard) is to require eliminating the exception if the generator is upgraded by 10% or more.** **6. The GO is expected to know what entity is its RC, PC, TO, and TP.** **7. The drafting team considered requiring an independent evaluation of existing generator exceptions and determined that it is not practical.** **8. No referenced documents are part of the Standard.** **9. The SDT considered including the Transmission Owner and determined that the Transmission Operator is the appropriate organization to receive the information.** **10. The 9 cycle maximum clearing time is intentional. It is not a system consideration, it is because generators cannot withstand zero voltage at the POI for long periods of time.**		
IRC Standards Review Committee	Yes	a. R5: The wording "the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation." is not written in a way to hold an entity responsible for any action. We suggest to reword it such that it places a responsibility to the Generator to seek approval for an exception, as follows: "the Generator Owner shall obtain approval for an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation through the submission of documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit within 30 days of identifying the equipment limitation. Along with this proposed change, there is also a need for the entities receiving the approval request to respond to the request. Another requirement is needed to complete this process. b. The latter part of R5 should be reworded to hold an entity responsible for the needed actions associated with expiring the exception such that the requirement is measurable and enforceable. c. R6: It is unclear to us what purpose this requirement serves. If R5 is to be revised as we suggest (see above), then the "limitation" in question will be presented with technical justification in the request for approval. The receiving entities (RC, PC, TOP and TP) will have a chance to accept or reject the request with due consideration of the technical argument. This is part of the approval request process; hence we do not see the need for R6 if R5 is to be reworded. If a remand process needs to be stipulated, then inclusion in R5 a requirement for the receiving entity(ies) to respond to the request - either approving or disproving the with a rationale, would suffice.
Response: Thank you for your comment. **a. The required action is for the GO to provide documentation of the equipment limitation. The SDT believes it is the GO's responsibility to determine any limitations on existing generators' ability to meet the Standard.**		

Organization	Yes or No	Question 9 Comment
b. The GO is responsible for meeting the requirements when an exception expires. **c. R6 (R4 in the revised standard) provides the RC, PC, TO, and TP with an opportunity to seek clarification concerning existing generator limitations in meeting the Standard.**		
Constellation Power Generation & Constellation Nuclear	Yes	The 4 kV protection that includes under frequency and under voltage relays trip the generator in some of our plants. The SDT needs to clarify whether this standard applies to such protection.
Response: Thank you for your comment. The Standard applies to setting of voltage and frequency relays that directly protect the generator.		
Southern Company	Yes	1. We recommend deleting the proposed section R2.2.2. If not deleted, change "meet a shorter voltage ride through" to "meet a less stringent voltage ride through". 2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field. 3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request" 4. How did the SDT translate the transient voltage excursion plot to the cumulative voltage curve? 5. The voltage ride through curve was said to be cumulative, this should be specified on the curve.6. How can we prove that our static voltage curve coordinates with this cumulative curve 7. Implementation schedule we believe that the unit size should be considered, and that the most critical units should be worked on first. Completing 33% each year is too ambitious for those members that have > 300 units. 8. What regions are working on voltage ride through and Underfrequency (ufls and undefrequency tripping of generators) 9. Should the PRC-024 SDT wait until the regions have completed their work? 10. Generator engineers do not see a relevance for a voltage ride-through for any generator other than wind.
Response: Thank you for your comment. **1. The SDT agrees and has modified the Standard to reflect this.** **2. The SDT intends this requirement to ensure timely notification of equipment changes to the PA and 30 days is a reasonable duration for the time horizon of the PA.** **3. The SDT agrees and has modified the Standard to reflect this.**		

Organization	Yes or No	Question 9 Comment
4. The SDT analyzed the amount of time the voltage remained outside of the required range in each of the events modeled. 5. The SDT has clarified the language. 6. A cumulative curve was selected to coordinate with relays that measure elapsed time. 7. The SDT set the timeframe by consensus among team members and the companies they represent. Stakeholder comments have not thus far objected to the implementation schedule. On this basis the SDT is leaving the schedule as proposed. 8. At the recommendation of FERC and NERC, the SDT has coordinated the UF relay curve with the NERC UFLS SDT members input. 9. At the recommendation of FERC and NERC, the SDT has coordinated the UF relay curve with the NERC UFLS SDT members' input. 10. The SDT has taken the direction to develop a Standard that is technology neutral.		
Converteam Naval Systems Inc.	Yes	0. (Overall) This is a good document that has good background study and contains a lot of expertise;1. (Voltage definition inconsistency)In the LVRT curves, it talks about the voltage at the point of interconnection. However, in R2.1 it uses voltage at the generator terminals. I think there is a little inconsistency between these two. It would be good to just use one of them, preferably the former one. The reason is that different generator plants might have different impedance between the generator terminals and the points of interconnection, so defining the voltage at the terminals poses a little unfairness. Another part of the reason is that for transmission protection purpose, it should ends at the point of interconnection.2. (Voltage range inconsistency)The voltage range is 0.9-1.1pu in the VRT curve, but it says 0.95-1.05 in R2.1. It would be good to make it consistent.3. (Date point missing) In the table supporting the VRT curves, the 0.95 and 1.05pu data are missing.4. (Priority) WECC and MRO have different VRT curves. Which one will override which one at the end? Will the NERC PRC-024 take priority than the Regional Entities? 5. Was reactive power support during faults considered in the draft group? Will it be required in the future Thanks
Response: Thank you for your comment. 0. Thank you! 1. The Standard applies to transient voltage excursions at the POI. R2.1 addresses steady state voltages at the generator terminals. 2. The VRT curve addresses the transient voltage event. R2.1 addresses steady state conditions, outside the range of the VRT curve. 3. The table addresses the transient voltage event and does not address steady state conditions. 4. This proposed standard is a NERC standard. The SDT is not addressing current or future regional Standards. 5. The Standard addresses voltage ride through. Reactive power and voltage support are important considerations in determining if a generator will meet the Standard. Methods to meet the Standard requirement are not specified in the Standard.		
Consumers Energy	Yes	Please see comments on Question 3.

Organization	Yes or No	Question 9 Comment
Company		
Response: Thank you for your comment. Please see responses to Question 3.		
Old Dominion Electric Cooperative	Yes	Provide some insight on Technical Exceptions for generators that cannot met these requirements (the CIP TFE process might be useful in this)
Response: Thank you for your comment. The SDT believes it is the responsibility of the GO to determine the capability of the existing units to meet the Standard.		
Southern California Edison Company	Yes	The curves and tables in the attachments require additional clarification.
Response: Thank you for your comments. Additional clarification has been added.		
Progress Energy, Inc.	Yes	1. Recommend deleting proposed R2.2.2. If not deleted the language needs to be clarified as follows: "meet a shorter voltage ride through" should be changed to "meet a less stringent voltage ride through".2. In R3, change "within 30 calendar days of any change" to "at least 30 calendar days prior to any change". The changes should be provided before they are made in the field.3. In M4, change "entities listed in Requirement 4" to "entities listed in Requirement 4 that provide a written request"4. The purpose and the applicability of the standard needs to be revised to clearly specify that the scope of PRC-024-1 only applies to main generator protective relaying and excludes protective functions associated with plant auxiliary equipment.
Response: Thank you for your comments. **1. The SDT agrees and has modified the Standard to reflect this.** **2. The SDT intends this requirement to ensure timely notification of equipment changes to the PA and 30 days is a reasonable during for the time horizon of the PA.** **3. The SDT agrees and has modified the Standard to reflect this.** **4. The Standard has been modified and now applies to overall new generator performance.**		
NIPSCo	Yes	R4 These groups should already have this information. The coordinators or planners should have proof and be able to provide this information now.R5 Normally would not accumulate enough time in the under-frequency zone to be a danger to the turbine blades but under unusual circumstances might accumulate too much time and not be able to continue to operate in the under-frequency region that is being specified. We might not have enough time to wait for the 30 day period.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. • **The purpose of the Standard is to assure that the relay setting information is available to the groups that require it.** • **Existing generators that are not able to meet the Standard are able to obtain an exception.**		
Northeast Utilities	Yes	R2.2.1 seems to imply that a generator must set an undervoltage trip with a time delay of no more than 9 cycles. This seems to conflict with the intent of PRC-024. Is the intent perhaps to require the TO to clear Zone 1 faults in no more than 9 cycles? Or is the intent to allow the GO to set the time delay as low as 9 cycles and no less? I suggest the latter.R3, R4, and R5 - This information should be provided to the owner of any UFLS or UVLS as well.
Response: Thank you for your comment. The intent is to allow TOs to reduce the required 9 cycle ride through requirement in cases where transmission system design allows faster clearing.		
Hydro-Québec TransEnergie (HQT)	Yes	Referencing R5 and R6 of the Standard: The Reliability Coordinator should be give veto power over exceptions to the requirements herein. Should the Generator Owner/Operator not be able to, or be unwilling to, make changes to setpoints to come into compliance with this Standard, the Reliability Coordinator should be given the authority to invoke required mitigation, such as requiring the Generator Owner/Operator to contract for compensatory load shedding up to the total amount of MW of each generating unit that fails to comply with the required setpoints. In addition, The "Off-Nominal Frequency Capability Curve" in Attachment 1 does not coordinate with the underfrequency load shedding (UFLS) program design parameters proposed by the NERC Underfrequency Load Shedding Standard Drafting Team for Project 2007-01. The misccoordination occurs in the time range approximatley between 5 and 10 seconds. This miscoordination can be eliminated by extending the horizontal line at 57.8 Hz to 5 seconds and revising the diagonal line to have endpoints at 57.8 Hz/5s and 59.5 Hz/1800s. This modification will provide coordination with the UFLS program design parameters while still maintaining coordination with turbine-generator capability. Due to the time scale on the graph in Attachment 2, the curves do not indicate the time at which the transient overvoltage and undervoltage requirements end, at which point the continuous voltage requirements would be applicable. Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above:> Concerning Attachment 1, we believe this is mainly present to infer that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled. > A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed relaying not to trip during" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective devised, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration applies to both frequency and voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations

Organization	Yes or No	Question 9 Comment
		which should be arrived at in consultation with the machine manufacturer.> Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this question will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted."> Concerning A.R2, this Standard addresses setting of voltage relays based on voltage at the point of interconnection, which is not directly translatable to voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard. We would like to commend the SDT for recognizing that there may be technical reasons that prevent a generator from meeting requirements 1 and 2 and allowing an exemption when technical basis is provided (R5). There is a paragraph on the second page which states that " For voltage excursions, only generator under or over voltage protective relays and volts per hertz relays would need to be evaluated to meet the draft requirements. Steady state evaluations only are expected "We have the following questions: (1) Do the relays mentioned in the statement above include auxiliary system undervoltage relays? It appears the voltage relay part of the standard is limited to only relays that directly trip the generator and not relays that trip auxiliaries. Is that the intent? What if the relay was attached to an auxiliary bus, but tripped the generator?(2) How is that only steady state evaluations are enough? How do you study voltage recovery characteristics without dynamic simulations?

Response: Thank you for your comment.

- **The GO has the responsibility for determining the capability of existing generators and their ability to meet this Standard. How the power system deals with the inability of an existing generator to meet the Standard requirements is not addressed in this Standard.**
- **The UFLS SDT and this Standard Drafting Team conferred and have coordinated the frequency curves and strategies.**
- **The voltage curve ends at 1000 seconds. Steady state limits apply after 600 seconds.**
- **Clarification has been added that the Standard does not require voltage or frequency protective relays to be installed or enabled.**
- **Clarification has been added concerning setting relays exactly on the curve.**
- **Clarification has been added concerning assumptions to be made when calculating generator terminal voltage settings that correspond to required POI limits.**
- **The Standard has been modified to also be a new generator performance standard.**
- **With respect to steady state evaluations versus dynamic simulations, the Standard does not preclude the application of either.**

Organization	Yes or No	Question 9 Comment
AESO	Yes	In addition to the SRC ISO/RTO comments the AESO would like to add: As we understand it, the intent of this standard is to ensure that the generators ride through certain levels of frequency and voltage excursions, yet it only addresses the generator protection. We feel it must also address the protection and capabilities of the auxiliaries, unit transformers, lines, etc. If any of these trip off due

Organization	Yes or No	Question 9 Comment
		to the same excursions that the generator is required to ride through, then the generator will be down and the standard will not have achieved its goal.

Response: Thank you for your comment. Based on industry input, the Standard has been modified to require new generators to ride through voltage and frequency excursions.

Organization	Yes or No	Question 9 Comment
Duke Energy	Yes	The issue typically addressed by international grid codes is an over-all plant performance standard and plant dynamic studies are performed to evaluate the impact on in-plant systems. Standards applicable to only generator protection might give a false sense that a plant could survive the transients and the reliability of the BES would be just as adversely impacted if large plants were to trip for causes other than a main generator relay. The basis and reliability benefit for voltage ride through transients should be clarified. Generator UF relays must coordinate with grid UFLS relaying. Some areas may apply UVLS and logic dictates that the coordination of that protection with a generator ride through criteria should be specified. Recommend that the scope of "equipment" that can be granted an exception be limited in some way or explicitly qualified. Otherwise, plant performance can be dictated by less-consequential auxiliary equipment (e.g. variable speed drives with UV settings per manufacturer standard instructions). Because R5 grants exception automatically in response to the GO providing documentation of any limitation. R5 bullet 2 - recommend changing "generator nameplate capacity rating" to "generator gross Real Power capability". The existing words are too general and including 'nameplate' is confusing.

Response: Thank you for your comment.

- **The Standard has been modified to require new generators to ride through voltage and frequency excursions.**
- **The UFLS SDT and this Standard Drafting Team conferred and have coordinated the frequency curves and strategies.**
- **The GO has the responsibility for determining the capability of existing generators and their ability to meet this Standard.**
- **The term "nameplate capacity" is not used in the revised standard.**

Organization	Yes or No	Question 9 Comment
New York Independent System Operator	Yes	Here are several other points that have come up regarding other parts of PRC-024-1 that were not covered above:> Concerning Attachment 1, we believe this is mainly present to insure that generator tripping will not interfere with UFLS programs. There should be a statement that settings should not interfere with UFLS program in effect. Also on Attachment 1, this is now labeled "Off Nominal Frequency Capability Curve." We wish to suggest that the word "capability" in this label is potentially misleading. This is not a machine capability curve. There should be a statement that protective device settings should be based on machine damage considerations and should be arrived at in consultation with the machine manufacturer. The curve presents limits to those settings which are designed to prevent interference with UFLS programs, and the curve should be so labeled.> A.R1 and A.R2 wording could be taken to require that such relaying should be enabled and set. The phrase "Installed relaying not to trip during" could be taken to mean that such relaying is assumed to be, or should be, installed. Also, in the case of generator multifunction protective device, such relaying is always installed but it is not appropriate in many cases that it be enabled and set. Note this consideration

Organization	Yes or No	Question 9 Comment
		applies to both frequency and Voltage. In general, this Standard should take care to point out that any protection application should be based on actual specific machine protective considerations which should be arrived at in consultation with the machine manufacturer.> Concerning A.R1.2 and Attachment 1, the language refers to a 'no trip zone" between curves, and obviously there is a permissible trip zone outside the curves. Questions will arise on permissibility of settings which are actually on the curves. We would suggest that setting directly on the curves should be permitted. For example, if 1.0 s. at 57.8 Hz is directly on the curve, failure to deal with this questions will result in pointless and counterproductive settings such as 1.0 s. at 57.79 Hz. We suggest "Setting directly on the curves are permitted, and settings outside the curves are permitted."> Concerning A.R2, this Standard addresses setting of Voltage relays based on Voltage at the point of interconnection, which is not directly translatable to Voltage at the generator terminals. The generator real and reactive power output will affect the relationship, and this is not dealt with in this Standard.
Response: Thank you for your comment. • **The UFLS SDT and this Standard Drafting Team conferred and have coordinated the frequency curves and strategies.** • **Determining existing generator capability is the responsibility of the GO.** • **Clarification has been added to make it clearer that the Standard does not require installing voltage or frequency protection relays nor does it require setting any relays at the curve values.**		
Xcel Energy	Yes	Please clarify if there is an expectation/requirement for new units to install voltage and frequency protective relays.
Response: Thank you for your comment. There is no requirement for any generator to install or have voltage or frequency protective relays. Clarification has been added.		
CenterPoint Energy	Yes	a) CenterPoint Energy is concerned with what appears to be a lack of consistency and coordination between standards efforts. Considering PRC-023, CenterPoint Energy believes it is illogical to have transmission relay loadability requirements based on 0.85 pu system voltage for an extended period (such as, 15 minutes) to allow system operators to take remedial actions, while exempting generators from comparable requirements. For another example, it appears this proposed standard is not consistent with that being proposed for under-frequency load shedding systems that can help prevent cascading outages. b) Requirements, such as R2.2.1 and R2.2.2, are essentially fill-in-the-blank, location-specific criteria that are unnecessary and could have unintended consequences. Location-specific criteria can change over time with additions and modifications of the transmission system. Entities will have no incentives to voluntarily exceed the minimum required criteria, even though their plant has a greater ride-though capability. R2.2.1 further allows relaying to be set on actual fault clearing times, instead of the 9 cycles indicated in Attachment 2. In addition, R2.2.2 allows the use of location-specific criteria, but only if such criteria are less stringent. CenterPoint Energy believes NERC reliability standards should not include fill-in-the-blank, location-specific criteria. CenterPoint Energy recommends modifying R2.2.1 to reference Attachment 2 and to clarify the ride-through criteria is zero voltage for 0.15 seconds (9 cycles). CenterPoint Energy recommends deleting R2.2.2. c) R5 allows generating plants to meet less stringent criteria if generator

Organization	Yes or No	Question 9 Comment
		manufacturer literature indicates limitations, which would further erode system support from generation resources. It does not appear there is any process to substantiate the legitimacy of such limitations. CenterPoint Energy recommends deleting R5 and associated references.
Response: Thank you for your comment. **a) The Standard has been modified to require new generators to ride through voltage and frequency excursions. The SDT has coordinated the development of the UF relay curve with UFLS SDT.** **b) Requirements R2.2.1 and R 2.2.2 (new R2.1.2) allow the TO to relax the voltage ride through requirements in specific cases where the transmission system is designed to accommodate reduced generator performance.** **c) New R3 exempts existing generators that are not capable of meeting the Standard's requirements from having to do so. The GO is responsible for determining the generator's capabilities.**		
Independent Electricity System Operator	Yes	a. R5: The wording "the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation." is not written in a way to hold an entity responsible for any action. We suggest to reword it such that it places a responsibility to the Generator to seek approval for an exception, as follows:"the Generator Owner shall obtain approval for an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation through the submission of documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit within 30 days of identifying the equipment limitation." The requirement for getting non-conforming protection approved should be so stipulated to put the onus for mitigating actions on the Generator Owners. For example, in the case of non-conforming underfrequency settings, the requesting Generator Owner should be required to demonstrate that mitigating (i.e. arrangements for additional compensating load shedding) measures have been arranged with the Balancing Authority in their submission. Equipment settings that infringe upon the curves may be implemented only after approval is granted by the appropriate entities. Along with this proposed change, there is also a need for the entities receiving the approval request to respond to the request. Another requirement is needed to complete this process. b. The latter part of R5 should be reworded to hold an entity responsible for the needed actions associated with expiring the exception such that the requirement is measurable and enforceable. c. R6: It is unclear to us what purpose this requirement serves. If R5 is to be revised as we suggest (see above), then the "limitation" in question will be presented with technical justification in the request for approval. The receiving entities (RC, PC, TOP and TP) will have a chance to accept or reject the request with due consideration of the technical argument. This is part of the approval request process, hence we do not see the need for R6 if R5 is to be reworded. If a remand process needs to be stipulated, then inclusion in R5 a requirement for the receiving entity(ies) to respond to the request - either approving or disproving the with a rationale, would suffice.
Response: Thank you for your comment.		

Organization	Yes or No	Question 9 Comment
a) The required action in new R3 is for the GO to provide documentation of the equipment limitation(s) to the RC, PC, TO, and TP. The GO is not required to seek approval. **b) The SDT believes that new R3 is measurable and enforceable.** **c) The purpose of new R3 is to exempt existing generators that are not capable of meeting the Standard from having to do so.**		
Ameren	Yes	This standard could be ineffective if someone's auxiliary power protection trips out on low voltage or frequency and brings the unit down before the generator protection. Those settings on the aux buses are there to protect the equipment from failure since most of the downstream loads such as motors and electronics won't ride through an excursion as well as large T/G sets. We suggest that ANSI/IEEE Standards C37.102, C50.12, and C50.13 should be used and listed as references to this Standard. Reporting mechanism in R3 and R4 raises some commercial concerns. We prefer a secure repository of reporting to the RRO. Then only those who do have valid reasons for studies or monitoring could be granted access to the information. Footnote 1 expands 'protective relays' definition to include voltage regulator, etc. Instead state that only direct trip elements (functions) in the voltage regulator and exciter are included, if that's the intent. It should be made very clear.
Response: Thank you for your comment. • **The Standard has been modified to require new generators to ride through voltage and frequency excursions.** • **The SDT recognizes that the information required to be reported must be protected appropriately and expects the receiving organizations will fulfill all of their information protection obligations.** • **Clarification has been added to footnote 1.**		
PPL Energy Plus	Yes	PPL is concerned with the following concepts in the standard: 1) The standard applies equally to asynchronous and synchronous machines, salient pole and round rotor machines, photovoltaic, and other resources and as such the standard does not appear to recognize that these technologies respond differently to voltage and frequency excursions. 2) Better clarity of generator owner and transmission owner roles regarding changing existing fault clearing times is needed in the proposed standard. 3) R2.2 requires further clarity regarding relay settings. 4) R3 and R4 look the same. 5) The reference paper under Section D needs a thorough review by the industry.
Response: Thank you for your comment. **1. The SDT has taken the direction to develop a Standard that is technology neutral.** **2. The TO is allowed to relax the relay setting standard (shorter durations or higher minimum voltages and or lower maximum voltages) if the full capability of the standards is not required in specific instances.** **3. Further clarification has been added.**		

Organization	Yes or No	Question 9 Comment
4. Old R3 and old R4 are combined into the new R6. **5. The SDT welcomes thorough industry review of the reference paper.**		
US Bureau of Reclamation	Yes	Requirements R3 and R4 place a coordinating role on the Generator Owner to provide trip settings to four entities, the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner. We believe it is more appropriate for the Generator Owner to coordinate settings with a single Transmission entity since the purpose of the Standard is "... to support transmission system stability during voltage and frequency excursions." and for the Transmission entity to further coordinate if necessary. The Transmission entity is in a better position to know what additional entities, if any should be involved. For the data points provided in the Attachment 2, HVRT DURATION and LVRT DURATION, we recommend both time and voltage units of measure be provided.
Response: Thank you for your comment. Old R3 and old R4 are combined into the new R6. The SDT agrees with the comment and has added clarification to the voltage and time units in Attachment 2		
American Transmission Company	No	It would be beneficial to have the option of measuring the voltage at the generator bus or point of interconnection (POI), with the understanding that the proper voltage must be maintained at the POI.
Response: Thank you for your comment. The SDT specifically chose the point of interconnection because that is where the faults occur that this Standard is intended to address. The SDT has provided additional assumptions for the calculation of relay settings on the basis of the voltage as measured at the POI.		
E.ON U.S.	No	
AWEA	No	
Luminant Power	No	
American Wind Energy Association	No	
Veolia Environmental Services	No	
Lakeland Electric	No	

Organization	Yes or No	Question 9 Comment
Manitoba Hydro	No	
American Electric Power	No	

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation System Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the excitation system model (including power system stabilizer model and impedance compensator model if so installed) and the model parameters used in dynamic simulations that assess Bulk Electric System (BES) reliability accurately represent generator excitation system behavior.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Operators of generating facilities:

4.1.1.1 Connected to Eastern or Quebec Interconnections with the following characteristics:

Each unit (including synchronous condensers) ≥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 200 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

4.1.1.2 Connected to Western Interconnection with the following characteristics:

Each unit (including synchronous condensers) ≥ 75 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 150 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

4.1.1.3 Connected to ERCOT Interconnection with the following characteristics:

Each unit (including synchronous condensers) ≥ 50 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

4.1.2 Transmission Planners**.**

Proposed Effective Date:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two years following applicable regulatory approval:
  - Each Generator Operator shall verify at least 10% of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, six years following applicable regulatory approval:
  - Each Generator Operator shall verify at least 50% (this includes the units verified in the first year) of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, eleven calendar years following applicable regulatory approval:
  - Each Generator Operator shall verify 100% of its applicable units.

In those jurisdictions where no regulatory approval is required:

- By the first day of the first calendar quarter, two years following Board of Trustees adoption:
  - Each Generator Operator shall verify at least 10% of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, six years following Board of Trustees adoption:
  - Each Generator Operator shall verify at least 50% (this includes the units verified in the first year) of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, eleven calendar years following Board of Trustees adoption:
  - Each Generator Operator shall verify 100% of its applicable units.

B. Requirements

R1. The Generator Operator shall verify the excitation system model (including power system stabilizer model and impedance compensator model if so installed) which represents generator excitation system behavior in dynamic simulations per the following schedules:

1) For a new or existing unit with a new excitation system, within 180 days of the commercial operation date or new equipment commissioning date, whichever occurs first.

2) For an existing unit, once in a ten calendar year period. If multiple units have the same MVA rating that is ≤ 250 MVA, and if they have identical applicable components and settings and are sited at the same physical location, verification of one unit is sufficient for all units. Verification shall be performed on a different unit each ten calendar year cycle.

3) If verification cannot be performed within the ten year period because a unit has not been on-line, the ten year period shall be extended. It is permissible to wait until the unit is scheduled to operate in order to conduct verification so that sufficient

advance notice to make arrangements for verification is available. After verification is performed, the subsequent ten year schedule for the next verification will start.

4) For units that reach an average Capacity Factor greater than 5% over the last three calendar years, and have not been verified within the last ten calendar years, verification shall be performed within the next calendar year. The subsequent ten year schedule will start upon a successful verification.

R2. The Transmission Planner shall provide the Generator Operator a set of model data sheets for the acceptable excitation system models (models cannot be confidential or proprietary) for use in dynamic simulation software, with each data sheet including the excitation system model block diagram structure and data requirements, within 30 calendar days of a request from the Generator Operator.

R3. The Transmission Planner shall provide the Generator Operator the unit specific data contained in the Transmission Planner's dynamic database from the current in-use excitation system model, within 30 calendar days of a request from the Generator Operator.

R4. The Generator Operator shall provide to the Transmission Planner the following unit specific information within 90 calendar days of completion of the excitation system model verification:

1) Manufacturer, model number if available, and type of excitation system (for example: static, ac brushless, dc rotating).

2) Generator model structure and data (reactances, time constants, saturation factors, rotational inertia)

3) Excitation system model structure and data for the closed loop voltage regulator (including main exciter if so equipped).

4) Reactive compensation settings (for example: reactive droop, line drop, differential compensation), if utilized.

5) Model structure and data for power system stabilizer, if so equipped.

R5. The Transmission Planner shall determine if the excitation system model is useable by including the excitation system model in dynamic simulation software and substantiating that:

1) A no-disturbance simulation contains no transients.

2) For an otherwise stable simulation, a disturbance simulation results in the equipment exhibiting positive damping.

R6. The Transmission Planner shall inform the Generator Operator whether the excitation system model is useable or not within 90 calendar days of receipt (R4). If the excitation system model is not useable, the Transmission Planner shall provide the Generator Operator with a description of the problem and any relevant details.

R7. The Generator Operator shall provide a written response within 90 calendar days following notification by the Transmission Planner that the excitation system model is not useable. The Generator Operator's response shall either:

- Indicate what changes will be made to the excitation system model, or
- Provide the technical basis why no changes will be made.

R8. The Generator Operator shall provide to the Transmission Planner documentation demonstrating that the excitation system model's response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) within 90 calendar days of completion of the excitation system model verification.

R9. The Generator Operator shall make documentation demonstrating that the excitation system model's response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) available for inspection and technical review to the Reliability Coordinators, Transmission Operators, and Planning Coordinators that have responsibility for the area in which the associated unit is located, within 60 calendar days after receipt of a request.

R10. The Generator Operator shall provide a written response within 90 calendar days after receipt of a Transmission Planner's or a Planning Coordinator's written comments detailing technical concerns with the Generator Operator's excitation system model verification documentation. That written response shall either:

- Indicate what changes will be made to the excitation system model, or
- Provide the technical basis why no changes will be made.

R11. The Generator Operator shall perform a review of its current excitation system model when its Transmission Operator or Reliability Coordinator provides the Generator Operator dated electronic or hard copy evidence that the recorded excitation control system response to a Transmission system event did not match the predicted excitation system model response. Upon review the Generator Operator shall either:

- Provide a dated electronic or hard copy explanation detailing why the current excitation system model is still appropriate within 90 days to the commenter and the Transmission Planner whose area the generating facility is located in, or
- Perform a re-verification in accordance with R4, and R8 within 180 days. Once the re-verification is performed, the 10 year period as outlined in R1 will be reset.

R12. The Generator Operator shall perform a review of its current excitation system model and model parameters each time an activity that may alter the equipment response is performed. An activity that potentially alters the response of the excitation system and/or power system stabilizer includes but is not limited to:

- Exciter, voltage regulator or power system stabilizer control replacement including software alterations that could alter excitation system equipment response
- Plant Digital Control System addition or replacement

- Plant Digital Control System software alterations that could alter excitation system equipment response
- Exciter, voltage regulator, impedance compensator or power system stabilizer settings change

The Generator Operator shall either:

- Provide documentation that the response has not changed to the Transmission Planner within 90 days of completion of an activity that could have altered equipment response, or
- Perform a re-verification in accordance with Requirements R4 and R8 within 180 days. Once the re-verification is performed, the ten year period as outlined in Requirement R1 is reset.

C. Measures

M1. (To be developed.)

References

The following documents contain technical information beyond the scope of this Standard on excitation system functions, models, and testing

1) IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines

2) IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems

3) IEEE 421.5 IEEE Recommended Practice for Excitation system Models for Power System Stability Studies

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Unofficial Comment Form for the First Draft of MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions (Project 2007-09)

Please **DO NOT** use this form to submit comments. Please use the **electronic comment form** located at the link below to submit comments on the proposed first draft of MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions developed by the standard drafting team as part of Project 2007-09 — Generator Verification. Comments must be submitted by **April 2, 2009**. If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at (860) 550-4157.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Background Information

The purpose of Project 2007-09 — Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024 — Verification of Generator Gross and Net Real Power Capability
- MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

And four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007.

- PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024 — Generator Performance During Frequency and Voltage Excursions
- MOD-026 —Verification of Models and Data for Generator Excitation System Functions
- MOD-027 — Verification of Generator Unit Frequency Response

MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions was developed with consideration to key issues stated in the SAR:

- Provide more details to the applicability section to identify any generators that should be exempt from compliance with the requirements in the standard,
- Replace the "fill in the blanks" requirements assigned to the Regional Reliability Organization which were appropriate when the standard was initially drafted but is

not appropriate under current requirements for approval of enforceable standards with a set of "continent-wide" requirements,

- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization,
- Consider and address issues identified during Phase III & IV field testing.

The SDT first considered the functional entity "applicability". The SDT quickly recognized that assigning responsibility to appropriate entities for a continent wide standard on verifying unit excitation system models would be difficult. The reason is that there are many business model variations regarding excitation model verification in place today. Some of these business models assign the Generation entity to be ultimately responsible for verification of the excitation system model, and some assign the Transmission entity to be ultimately responsible. After lengthy discussions, the SDT decided that a Generation entity was the appropriate entity to assign ultimate responsibility. Therefore, in all instances of Requirements involving interaction (regarding the excitation system models) between the Generation entity and the Transmission entity, the Requirements are drafted such that the Generation entity has the final excitation system model responsibility and authority.

Consistent with the philosophy being proposed for MOD-024-1, the SDT concluded that while the Generator Owner may be responsible for the verified excitation system models, it is the Generator Operator that is the responsible entity to "operate" the unit in such a way as to obtain the required verification and any associated analysis; under the permission of the Generator Owner. The SDT felt that it is up to the Generator Owner and Generator Operator to work out any contractual arrangements associated with this relationship.

The SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80 percent or greater of the connected MVA per Interconnection. Therefore, the SDT proposes specific MVA thresholds for each interconnection. The SDT selected the MVA thresholds to correspond to 80 percent of the MVA for each interconnection. The SDT further felt that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, was appropriate. The SDT believes that these applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Finally, the SDT believes that this standard should not apply to units with a low capacity factor. The SDT was unable to obtain substantiating data before this posting to substantiate the low capacity factor concept and thus is asking industry for input.

The SDT is proposing a 10 year recurring cycle for excitation system model verification. A 10 year cycle is being proposed in recognition of the expectation that as new units continue to be installed, an increasing percentage of digital excitation systems will be in service. The SDT felt that a 10 year recurring cycle, especially with technologies associated with digital excitation systems, would result in high confidence that the model represented actual equipment performance. If the inputs and outputs of an excitation system test performed on the same equipment 10 years apart are identical, and there is no technical reason to utilize a different model block diagram structure, the original verification documentation can be re-used. The SDT plans to allow this philosophy through the Measures which will be written for industry review at a later date.

The SDT recognized that observed performance of one excitation system installed for one generator should be expected, with high confidence, to have the same performance for a similar excitation system installed with identical settings for an identical generator. Based on that premise, the SDT thought that it would be prudent to allow a single unit verification to potentially count for multiple units which a) have the same MVA rating which is ≤ 250 MVA b) have identical applicable components and settings and c) are sited at the same physical location. The SDT felt that this philosophy would allow maximization of limited resources required to perform model verification without sacrificing reliability to the BES. This philosophy is expected to include units at the vast majority of combined cycle and multiple unit combustion turbine plants.

The SDT drafted the standard to capture interactions between the Generator Operator and predominately the Transmission Planner in an expected chronological order. Draft Requirements R2 and R3 ensure that the Transmission Planner supplies the Generator Owner an approved list of excitation system model data sheets and the unit specific excitation system models upon request. Requirement R4 lists the unit specific information that the Generator Operator is required to provide to the Transmission Planner upon completion of model verification. In addition to the excitation system model and model data, the Generator Operator is required to supply the generator model data used in the excitation system verification process. The reason is that the excitation system and generator that has been tested are part of a closed loop system. Thus, in reality, both the excitation system and portions of the generator dynamic models are being verified. The SDT stopped short of requiring verification of generator model data, in part because it would arguably result in an increase in scope not covered by the original Generation Verification SAR.

Once the unit specific information, including the model and model data, is received by the Transmission Planner, the Transmission Planner per Requirement R5 must determine if the model is useable. The activity to determine if the model is useable should not be confused with the model verification activity of ensuring the model response matches actual equipment response. A model is considered “useable” if it does not cause angle drift in a no-disturbance simulation or unduly causes poorly or un-damped oscillations in a dynamic simulation of a mild system fault disturbance. If the model is found to be unusable, Requirement R6 affords the opportunity for the Transmission Planner to request assistance from the Generator Operator, with the Generator Operator having the final technical authority (R7).

Based on a review of the Field Test results and experience of the SDT members, the SDT recognized that an excitation system model verification standard could be developed much like a technical procedure manual. It is anticipated that traditional staged testing as typically performed during commissioning of new equipment will be the primary form of data collection for model validation and documentation (R8 and R9) for the foreseeable future. However, the SDT felt that the standard should neither discourage innovation nor be dependent on emerging technologies. The SDT felt that the standard should be written so that applicable techniques that are under development but perhaps years away from being mainstreamed should still fit well within the standard Requirements. Thus, the SDT drafted a standard that concentrates on “stating what is required” but without “stating how to accomplish what is required". As an example, there are industry efforts to increase the use of ambient monitoring to verify excitation system models. The basic idea is to set up monitoring equipment to capture the response of the unit to naturally occurring transmission system upsets that result in an excitation system response. By capturing key electrical parameters associated with the excitation system response, the predicted model response can be compared to the actual equipment response. The use of ambient monitoring to verify excitation system models has been successfully implemented, but the implementation throughout the industry to date is extremely limited. Thus, the SDT has strived to develop the draft standard with minimal technical specificity so that ambient monitoring and other future techniques can be refined and utilized while still satisfying the Requirements. The draft standard does include a "peer review" process for the verification documentation, again, with the Generator Operator having the final technical authority (R10)

The final two Requirements deal with situations where the Generator Operator would review the excitation system model and/or model verification documentation. The review could be based either on observation of unexpected equipment performance by the Transmission Operator or Reliability Coordinator, or by activities that could result in an alteration of equipment performance. If a re-verification occurs before the 10 year recurring cycle is complete, the 10 year cycle would be re-set. The list of activities in Requirement R11 which could trigger a review includes Plant Digital Control System (DCS) additions, replacements, or software alterations. Plant DCS activities would only be relevant to excitation system modifications if they involved the addition, deletion, or modification of an outer loop control (such as power factor or reactive power set point) that alters automatic voltage regulator action.

The following questions will assist the SDT in finalizing the development of MOD-026-1. For questions where you agree with the SDT, please state that you agree with any explanatory comments and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. The SDT would appreciate responses to as many of these questions as you can answer.

1. The SDT recognized that a determination had to be made regarding which entity should be ultimately responsible for model verification. The SDT was of the opinion that the Generator Operator, instead of the Transmission Planner or Generator Owner, was the appropriate entity to be responsible for the model verification. The Generator Operator operates the equipment being verified, and has direct access to the equipment. The Transmission Planner has the simulation software, but does not typically have access to the equipment or have testing capabilities. It is recognized that Generator Operators typically do not have in-house expertise and would have to either hire consultants to perform model verification, or develop in-house expertise including acquiring simulation software.

   Do you agree that the Generator Operator should be responsible for model verification? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT recognizes that depending on the technology of the modeled equipment, the periodicity of model verification necessary to ensure accurate models could vary. Also, the team recognizes that the majority of the resulting reliability benefit will occur during the initial verification. The drafting team determined that 10 years would be an appropriate period for re-verification in the absence of other activities listed in Requirement R12 that would require an earlier re-verification.

   Do you agree that 10 years is an appropriate period for re-verification? If you recommend a different period, please state your reasoning.

   ☐ Yes

   ☐ No

   Recommended periodicity and reasoning:

3. The SDT thought that it would be reasonable to apply a philosophy to allow maximization of limited resources required to perform excitation system model verification. The philosophy allows a single unit's actual excitation system verification to be a proxy for multiple units if the following conditions are met: a) the units have the same MVA rating, b) the units are rated at ≤ 250 MVA c) the units have identical applicable components and settings and d) the units are sited at the same physical location. For each recurring 10 year cycle, another unit must actually be verified.

   Do you agree with the proxy unit approach as used in Requirement R1 Item 2? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

4. The list of unit specific information in Requirement R4 to be provided to the Transmission Planner from the Generator Owner includes generator data used in the

excitation system verification process. The reason is that the tests, ambient or staged, which are used to verify the excitation system model, are part of a closed loop system that includes the generator. However, the SDT stopped short of requiring verification of either all generator data, or a portion of the generator data which is most applicable to excitation system testing (Transient Open Circuit Time Constant, and for PSS model verification, rotational inertia). The SDT feels that it cannot develop draft Requirements for the verification of generator data without submitting a supplementary SAR to the NERC Standards Committee.

Do you agree with the approach of requiring the Generator Owner to supply the generator data used in the excitation system model verification?

☐ Yes

☐ No

Comments:

Do you believe that the SDT should consider expanding the scope, through a supplementary SAR, to include verification of generator data? If yes, please provide the scope of generation verification the SDT should consider, along with any data that would support the reliability benefits from expansion of the existing scope which could be included in a supplementary SAR.

☐ Yes

☐ No

Comments and/or supporting data:

5. MOD-026 Requirement R8 requires the Generator Operator to provide documentation demonstrating that the provided model's response matches the recorded response. It does not specify criteria for evaluating the match. Requirement R8 assigns the task of evaluating the match to the Generator Operator. A peer review process for this documentation, detailed in Requirement R10, gives other involved parties an avenue to provide input and voice any concerns.

Do you agree with the approach of the Generator Operator determining if the match is sufficient and the peer review process?

☐ Yes

☐ No

Comments:

6. The team purposely provided minimal specificity regarding the mechanics of performing excitation system verification and the development of the documentation showing that the provided model response matches the recorded response. The team felt it was impractical to provide verification details in a mandatory Reliability Standard that needs to be applicable to all of the existing and future technologies.

Do you agree with this approach? If no, please elaborate on the additional specificity that you feel is appropriate with specific examples and/or proposed Reliability Standard language.

☐ Yes

☐ No

Comments:

7. The SDT believes that this standard should not be applicable to low capacity factor units. The SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already accurately replicate actual equipment performance. By definition, low capacity factor units are expected to rarely be on-line, and even when they are, they would constitute a small portion of the interconnected MVA. As such, the SDT is of the opinion that verified excitation models for these units would not result in a substantial increase in Bulk Electric System reliability. Do you agree with this approach and the proposed 5% capacity factor?

☐ Yes, agree with approach and the 5% capacity factor

Supporting data for the proposed 5% capacity factor:

☐ Yes, agree with the approach. But use another capacity factor (include supporting data):

☐ No (disagree with approach)

Comments and/or supporting data for not agreeing with a capacity factor exemption:

8. The SDT is of the opinion, based upon sound engineering judgment, that verifying models for excitation systems of generators per the MVA thresholds specified in the Applicability section 4.1.1 will ensure satisfactory performance of Interconnection network simulation models. Do you agree with this approach? If yes, please provide any data in support of the proposed approach including supporting data that the MVA thresholds specified in the Applicability section 4.1.1 correspond to 80% of the Interconnection MVA.

☐ Yes

Supporting data:

☐ No, instead use this approach:

9. Do you believe the SDT should develop a Requirement to allow the Transmission Planner or the Planning Coordinator to identify additional applicable units beyond those specified in section 4.1.1 due to their criticality to the reliability of the Bulk Electric System? If yes, please include the criteria that should be used by the Transmission Planner or Planning Coordinator to identify critical units with MVA rating less than listed in section 4.1.1 and any supporting data.

☐ Yes

☐ No

Comments and/or supporting data:

10. The SDT is proposing an implementation plan that requires certain percentages of applicable units to be verified two, six, and eleven years after the standard is approved. The SDT also thought it would be prudent to allow the verification of excitation systems per Regional Entity procedures and guidelines within 5 years of the approval date to be sufficient for demonstrating compliance with this new Reliability Standard.
Do you agree with these approaches?

☐ Yes, agree with proposed phase in period for unit excitation system verification

☐ No, the phase in period for unit excitation system verification should be:

☐ Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date

☐ No, instead of allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date, instead would recommend:

11. If you are aware of any regional variances that would be required as a result of this standard, please identify them here.

Regional Variance:

Comments:

12. If you are aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

Conflict:

Comments:

13. If you have any other questions or concerns with the proposed standard that have not been addressed in responding to the questions above, please provide them here.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Field Tested Version of MOD-026 Mapped to Proposed MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
2. Number: MOD-026-1	Proposed standard will only cover MOD-026-1 content and will not be merged with any other standard	**2. Number:** MOD-026-1
1. Title: Verification of Models and Data for Generator Excitation System Functions	Title is unchanged	**1. Title:** Verification of Models and Data for Generator Excitation System Functions
3. Purpose: To ensure accurate information on generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) is available for models used to assess bulk electric system reliability.	The Purpose has been modified to emphasize verification of models, as opposed to data reporting already covered in MOD-012 and MOD-013.	**3. Purpose:** To verify that the excitation system model (including power system stabilizer model and impedance compensator model if so installed) and the model parameters used in dynamic simulations that assess Bulk Electric System (BES) reliability accurately represent generator excitation system behavior.
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated. Transmission Planner is added as this functional entity is involved in the iterative process of validating dynamic models. Additionally, generating facilities have been limited to those that have significant	**4. Applicability:** **4.1. Functional entities** **4.1.1** Generator Operators of generating facilities: **4.1.1.1** Connected to Eastern or Quebec Interconnections with the following characteristics**:** Each unit (including synchronous condensers) ≥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years. Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 200 MVA, connected at the

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	impact to BES reliability as they consist of approximately 80% of the connected MVA in each Interconnection	point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years. **4.1.1.2** Connected to Western Interconnection with the following characteristics**:** Each unit (including synchronous condensers) ≥ 75 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years. Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 150 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years. **4.1.1.3** Connected to ERCOT Interconnection with the following characteristics: Each unit (including synchronous condensers) ≥ 50 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years. Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years. **4.1.2** Transmission Planners**.**
R1. The regional reliability organization shall establish and maintain procedures to address	Regional applicability is eliminated and functional entity	**Requirements R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, & R12** define the model verification process which would have been

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
verification of models and data associated with generator excitation system functions including voltage regulator controls, limiters, compensators, and power system stabilizers. These procedures shall include the following:	responsibility is defined Verification, including reporting, is addressed throughout proposed Standard. Voltage regulator controls are inherent to excitation models. Some generators include power system stabilizer equipment that has an associated individual model and model data. Under and over excitation limiter static set points will be addressed in MOD-025 and/or PRC-019. Any reactive compensation settings are to be provided to the Transmission Planner so that the Transmission Planner can model these set points and settings as appropriate (reference IEEE 421.5-2005 for additional information).	addressed by regional procedures. Following is a high level summary of each of the Requirements: **R1.** Statement of the GOP Schedule (periodicity, extensions, exceptions) for verifying the excitation system model **R2.** TP provides a set of model data sheets to the GOP within 30 days of a request **R3**. TP provides the current unit specific excitation system dynamics data to the GOP within 30 days of a request **R4.** GOP provides the verified unit information to the TP **R5.** TP confirms that the provided models (R4) runs on its software **R6.** TP informs GOP if the provided model ran on the TP software, and if not, provides details. **R7**. If the model did not run on the TP software, the GOP provides the TP a written response with proposed solutions or a reason why no solution is offered **R8.** GOP provides TP information regarding the correlation of actual equipment to model simulated response **R9.** GOP provides RCs, TOs, and PCs information regarding the correlation of actual equipment to model simulated response within 60 days of a request **R10**. GOP responds within 90 days to a technical concern if initiated by the TP/PC **R11.** Within 90 days of receiving evidence by the TOP or RC that the equipment's response to a due to a transmission system event did not match the predicted model response, the GOP reviews its model(s) and provides the TOP or RC and applicable TP either an explanation or a re-verification of the model(s). **R12.** List of activities that potentially alter equipment response and thus could trigger a re-verification within a 10 year cycle

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by **Applicability Section 4.1 and its sub-sections** by stating which generators are applicable to this Standard. Two criteria are utilized in specifying applicability: MVA and capacity factor. Unit MVA and plant MVA cutoffs for each NERC Interconnection are based on a total connected MVA of 80% being subjected to model verification.	**Sections 4.1 and sub sections are mapped above**
R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.	**Requirement R8** requires the Generator Operator to provide to the Transmission Planner documentation verifying that the provided model response matches the recorded response. Rather than establishing rigorous testing details, the Standard simply requires that the verification methodology chosen shall result in good correlation between model response and a recorded response. The recorded response could be from a staged test or ambient event. Additionally, **R9** requires the	**R8.** The Generator Operator shall provide to the Transmission Planner documentation demonstrating that the excitation system model's response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) within 90 calendar days of completion of the excitation system model verification. **R9.** The Generator Operator shall make documentation demonstrating that the excitation system model's response

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	Generator Operator to make the documentation available to its Transmission Planner (R9) and others (RC, TO, PC) which have responsibility for the area where the generator is located. This replaces part of a "catch-all" requirement of the Field Tested Version R3 mapped below.	matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) available for inspection and technical review to the Reliability Coordinators, Transmission Operators, and Planning Coordinators that have responsibility for the area in which the associated unit is located, within 60 calendar days after receipt of a request.
R1.3 Periodicity and schedule of verification and reporting, including schedules associated with field changes to existing units, and refurbished units.	Requirements **R1** and its sub requirements and **R10** address periodicity and schedules The intent of **R1 Item 1** is to provide ample time to perform verification for new equipment. Prior to verification, models and data would be made available to the Transmission Planner via Interconnection agreements and the process detailed in MOD-012 and 013. **R1 Item 2** specifies a 10 year recurring verification cycle and defines allowable opportunities to reuse the results of the validation of a unit's model for other units that meet the criteria listed in Item 2. A 250 MVA cutoff results in the inclusion of one of the most logical and likely beneficiaries of this	**R1.** The Generator Operator shall verify the excitation system model (including power system stabilizer model and impedance compensator model if so installed) which represents generator excitation system behavior in dynamic simulations per the following schedules: 1) For a new or existing unit with a new excitation system, within 180 days of the commercial operation date or new equipment commissioning date, whichever occurs first. 2) For an existing unit, once in a ten calendar year period. If multiple units have the same MVA rating that is ≤ 250 MVA and if they have identical applicable components and settings and are sited at the same physical location, verification of one unit is sufficient for all units. Verification shall be performed on a different unit each ten calendar year cycle.

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	"proxy" unit philosophy - relatively new Combined Cycle and multiple Combustion Turbine plants (i.e., a "CT farm") with digital excitation systems **R1.3** details allowable time delays beyond the standard 10 year verification cycle for units that have not been on-line. **R1 Item 4** addresses verification schedules for units that were exempt due to a low capacity factor, but transition to having a capacity factor of greater than 5% R11 requires the Generator Owner to review the model when notified by the Transmission Operator or Reliability Coordinator that the actual equipment response observed during a transmission system event deviated from what was predicted by the model. Upon such notification, the GO must either provide an explanation or re-verify the model. The Requirement is written in such a manner to	3) If verification cannot be performed within the ten year period because a unit has not been on-line, the ten year period shall be extended. It is permissible to wait until the unit is scheduled to operate in order to conduct verification so that sufficient advance notice to make arrangements for verification is available. After verification is performed, the subsequent ten year schedule for the next verification will start. 4) For units that reach an average Capacity Factor greater than 5% over the last three calendar years, and have not been verified within the last ten calendar years, verification shall be performed within the next calendar year. The subsequent ten year schedule will start upon a successful verification. **R11.** The Generator Operator shall perform a review of its current excitation system model when its Transmission Operator or Reliability Coordinator provides the Generator Operator dated electronic or hard copy evidence that the recorded excitation control system response to a Transmission system event did not match the predicted excitation system model response. Upon review the Generator Operator shall either: • Provide a dated electronic or hard copy explanation detailing why the current excitation system model is still appropriate within 90 days to the commenter and the Transmission Planner whose area the generating facility is located in, or • Perform a re-verification in accordance with R4, and R8 within 180 days. Once the re-verification is

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	ensure the applicable Transmission Planner has up to date information regarding the model. **R12** lists activities that could result in an alteration of equipment response which necessitates the need for model re-verification due to field changes.	performed, the 10 year period as outlined in R1 will be reset. **R12.** The Generator Operator shall perform a review of its current excitation system model and model parameters each time an activity that may alter the equipment response is performed. An activity that potentially alters the response of the excitation system and/or power system stabilizer includes but is not limited to: • Exciter, voltage regulator or power system stabilizer control replacement including software alterations that could alter excitation system equipment response • Plant Digital Control System addition or replacement • Plant Digital Control System software alterations that could alter excitation system equipment response • Exciter, voltage regulator, impedance compensator or power system stabilizer settings change The Generator Operator shall either: • Provide documentation that the response has not changed to the Transmission Planner within 90 days of completion of an activity that could have altered equipment response, or • Perform a re-verification in accordance with Requirements R4 and R8 within 180 days. Once the re-verification is performed, the ten year period as outlined in Requirement R1 is reset.
R1.4. Information to be reported related to generator excitation system functions:	**Requirements R2, R3, R4, R7, and R8** addresses information to be reported from the Generator Operator, and associated	

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	interactions between the Generator Operator and the Transmission Planner.	
R1.4.1. Verified manufacturer and type of excitation system/voltage regulator control system (static, brushless, rotating, etc.).	Field Test Ver. R1.4.1 is covered by proposed R4.	**R4.** The Generator Operator shall provide to the Transmission Planner the following unit specific information within 90 calendar days of completion of the excitation system model verification: **1)** Manufacturer, model number if available, and type of excitation system (for example: static, ac brushless, dc rotating). **2)** Generator model structure and data (reactances, time constants, saturation factors, rotational inertia) **3)** Excitation system model structure and data for the closed loop voltage regulator (including main exciter if so equipped). **4)** Reactive compensation settings (for example: reactive droop, line drop, differential compensation), if utilized. **5)** Model structure and data for power system stabilizer, if so equipped.
R1.4.2. Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits.	Field Test Ver. R1.4.2 is covered by proposed R4. The model data is specified as part of the list in R4. In additional to providing additional specificity, the current draft Standard's R4 contains specific reference to Generator model data that was not part of the Field Test Version of the Standard. This is because the generator and excitation system data are all included in the closed loop system being verified.	
R1.4.3. Verified static set points for under and over excitation limiters.	The information on verified static set points in Field Test Ver. R1.4.3 has been removed.	

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	Static set points for UEL and OELs will be addressed in MOD-025 and/or PRC-019.	
R1.4.4. Verified line drop compensator settings.	R1.4.4 is covered by R4. See additional comments above for NERC Field Test Ver. R1.	
R1.4.5. Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).	Additional options beyond the specific Open circuit test referenced in Field Test R1.4.5 have been included in R8.	**R8 is mapped above**
	R10 is a new requirement which provides the opportunity for a technical exchange between the GO and the TP and/or PC regarding the verified documentation specified in R8.	**R10.** The Generator Operator shall provide a written response within 90 calendar days after receipt of a Transmission Planner's or a Planning Coordinator's written comments detailing technical concerns with the Generator Operator's excitation system model verification documentation. That written response shall either: • Indicate what changes will be made to the excitation system model, or • Provide the technical basis why no changes will be made.
R1.4.6. Verified model for each power system stabilizer with associated gains, time constants, and limits.	Same comments apply to Field Test Ver. R1.4.6 as noted directly above for Field Test Ver. R1.4.2.	

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
R1.4.7. Method of verification, including the date of verification, with the voltage regulator in the automatic voltage control mode.	Field Test R1.4.7 is covered in R8 Reference to "the voltage regulator in the automatic voltage control mode" in the Field Test Version Standard was removed in this draft Standard as it is a statement of the obvious.	**R8 is mapped above**
R2. The regional reliability organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, to the generator owners, generator operators, transmission operators, planning authorities, and transmission planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. This proposed Reliability Standard in its entirety (**R1 – R12**) specifies continent-wide verification and reporting procedures.	**R1 – R12 are mapped above**
R3. The generator owner shall follow its regional reliability organization's procedures for verifying and reporting its models and data associated with the generator excitation system functions per requirement 1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. **R1, R4, R7, R8, R9, R10, R11, and R12** defines the procedures to be followed by the Generator Operator for verifying and	**R1, R4, R7, R8, R9, R10, R11, and R12 are mapped above**

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	reporting its model and data.	
	R2 and R3 are new requirements which, upon request of the Generator Operator: 1) Ensures the Transmission Planner provides a list of acceptable excitation system model data sheets 2) Ensures the Transmission Planner provides unit specific excitation system model data currently being utilized in the Transmission Planner's dynamic database	**R2.** The Transmission Planner shall provide the Generator Operator a set of model data sheets for the acceptable excitation system models (models cannot be confidential or proprietary) for use in dynamic simulation software, with each data sheet including the excitation system model block diagram structure and data requirements, within 30 calendar days of a request from the Generator Operator. **R3.** The Transmission Planner shall provide the Generator Operator the unit specific data contained in the Transmission Planner's dynamic database from the current in-use excitation system model, within 30 calendar days of a request from the Generator Operator.
	R5, R6 and R7 are new requirements which: 1) Ensures that the Transmission Planner tests the developed model to assess if the model is useable in the dynamic simulation software 2) Ensures the Generator Operator is promptly notified that the model is useable or not 3) Provides a process for the Generator Operator and Transmission Planner to work together to resolve usability issues.	**R5.** The Transmission Planner shall determine if the excitation system model is useable by including the excitation system model in dynamic simulation software and substantiating that: 1) A no-disturbance simulation contains no transients. 2) For an otherwise stable simulation, a disturbance simulation results in the equipment exhibiting positive damping. **R6**. The Transmission Planner shall inform the Generator Operator whether the excitation system model is useable or not within 90 calendar days of receipt (R4). If the excitation system model is not useable, the Transmission Planner shall provide the Generator Operator with a description of the problem and any relevant details. **R7**. The Generator Operator shall provide a written response within 90 calendar days following notification by the Transmission Planner that the excitation system model is not useable. The Generator Operator's response shall either:

Field Tested Version of MOD-026	Comment	Proposed MOD-026-1
	It is stressed that a "useable" model is simply a model which does not unexpectedly negatively impact otherwise stable dynamic simulation. An example might be a model which contains a parameter that has been incorrectly scaled thus causing dynamic simulation solution convergence issues. A model can be "useable", but it may or may not be representative of the installed equipment performance.	• Indicate what changes will be made to the excitation system model, or • Provide the technical basis why no changes will be made. .

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Periods Open
February 17 – April 2, 2009

Now available at: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Two Proposed Standards for Project 2007-09 — Generator Verification

The Generator Verification Standard Drafting Team (Project 2007-09) has posted drafts of two proposed standards for 45-day comment periods. Mapping documents that compare these standards with field-tested versions are also posted. The comment periods are now **open until 8 p.m. EDT on April 2, 2009**. Please use the electronic forms (see links below) to submit comments. If you experience any difficulties in using the electronic forms, please contact Lauren Koller at 609-524-7047. Off-line, unofficial copies of the comment forms are posted on the project page: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

Electronic comment form:
https://www.nerc.net/nercsurvey/Survey.aspx?s=aaa41c53fb80462e8783344cd70f6ce0

Note: the drafting team will hold a WebEx to explain the concepts in proposed standard PRC-024-1 on February 26 from 2 p.m. to 4 p.m. EST. More information about the WebEx will be sent in a separate announcement.

MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions

Electronic comment form:
https://www.nerc.net/nercsurvey/Survey.aspx?s=7b8a364e930f4c1a87a792881c9b94dd

Background

Project 2007-09 includes six standards to address generator verifications needed to support bulk power system reliability – four proposed standards and revisions to two existing standards. The purpose of the project is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

More information is available on the project Web page:
http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Newsroom Site Map Contact NERC

Individual or group. (45 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (16 Responses)
Lead Contact (16 Responses)
Contact Organization (16 Responses)
Question 1 (45 Responses)
Question 1 Comments (45 Responses)
Question 2 (45 Responses)
Question 2 Comments (45 Responses)
Question 3 (43 Responses)
Question 3 Comments (45 Responses)
Question 4 (44 Responses)
Question 4 Comments (45 Responses)
Question 4 (43 Responses)
Question 4 Comments and/or supporting data: (45 Responses)
Question 5 (45 Responses)
Question 5 Comments (45 Responses)
Question 6 (45 Responses)
Question 6 Comments (45 Responses)
Question 7 (44 Responses)
Question 7 Comments (45 Responses)
Question 7 Comments (45 Responses)
Question 8 (41 Responses)
Question 8 Comments (45 Responses)
Question 9 (41 Responses)
Question 9 Comments (45 Responses)
Question 10 (43 Responses)
Question 10 Comments (45 Responses)
Question 11 (0 Responses)
Question 11 Comments (45 Responses)
Question 12 (0 Responses)
Question 12 Comments (45 Responses)
Question 13 (0 Responses)
Question 13 Comments (45 Responses)

Individual
Russell A. Noble
Cowlitz County PUD
Yes
Did you mean to say above that Generator Owners typically do not have in-house expertise and would have to either hire...? YES - Cowlitz as a Generator Owner does not have the in house expertise. Delays result in our efforts to obtain modeling information as we try and find consultants willing to do the work. The Generator Operator is the entity which should be held responsible.
Yes
Yes
No
I think you meant for the Generator Operator to supply the generator data.
No

Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
No
Yes, agree with proposed phase in period for unit excitation system verification
Group
NERC Event Analysis & Information Exchange staff
Robert W. Cummings
NERC
No
Comments: Although verification (not validation) of generator equipment settings and testing should be the responsibility of the GO, validation of generator models response to actual system events should be done by the Reliability Coordinator. This offers independent oversight of the validation. Also, validation to system events should be done for multiple events. This provides better insight to generator excitation and control performance over a wider range of conditions than a single staged test.
Yes
Ten years is an adequate backstop for re-testing. However, it should additionally be tempered by performance differences observed during validation to actual or staged system events. Repeated matching of model performance to events should also make a ten year test unnecessary.
Yes
As long as no actual differences are observed during performance comparisons to actual system events, this is an acceptable shortcut.
No
See below.
Yes
It seems that having an overall generator testing standard in place on the dynamic parameters listed in MOD-013 would be a prerequisite for an excitation testing standard.
No
The peer review process in R10 assumes that since the GOP operates the equipment, they are a technical authority on its modeling and behavior. Historically, that has been not necessarily correct, even of the owners of the equipment. Changes to excitation system models should be peer reviewed. However, a dispute resolution process would be needed for disagreements between the owners/operators and the peer team.
Yes
No (disagree with approach)
Units with a low capacity factor may well still be frequently needed, albeit for short but crucial periods, to support the system during peak load. Further, they may often be used in â €œshoulder periodsâ€ when primary resources are out on maintenance.
No, instead use the approach below:
There are a number of units that, through switching, can operate in multiple interconnections, making it hard to decide where they belong. To reduce complexity in administration, avoid confusion, and to have a more level playing field in North America, the standard registration thresholds of units â ‰ ¥ 20 MVA per machine and â ‰ ¥ 75 MVA per plant should be applied.
Yes
It is essential that the Planning Coordinator and Reliability Coordinator be allowed to designate

other critical units. In some cases, despite their size, the aggregation of a number of small units can have a significant impact on the dynamics of an area. One example is the transfer capability across the state of Maine, which is influenced by the dynamics of the multiple small hydro units in the state. Similarly, the dynamic performance of small units may be critical to reliability in some local areas such as New Brunswick and Nova Scotia.
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
It seems that having an overall generator testing standard in place on the dynamic parameters listed in MOD-013 would be a prerequisite for an excitation testing standard.
Individual
Brent Ingebrigtson
E.ON U.S.
Yes
No
E.ON U.S. believes that verification data and model results should not change over time. Therefore, a re-verification schedule is not necessary. E.ON U.S recommends that verification be required whenever new equipment is installed.
No
E.ON U.S. does believe that the proxy process described is reasonable. As expressed in the response to question 2, E.ON U.S. believes that, absent installation of new equipment, a re-verification schedule is unnecessary.
Yes
No
E.ON U.S. believes that entities have no incentive to use inaccurate data when conducting verifications studies. Strict data verification standards are in this instance an unproductive use of resources.
Yes
No
While E.ON U.S. appreciates that the concern over requirements applicable to both existing and future technologies, the lack of any specific guidance on process and verification methodologies invites differing interpretations of the standard. This lack of specificity makes compliance problematic.
Yes agree with approach and the 5% capacity factor
Yes
No
The generation owner/operator is in the best position to identify those facilities that require verification studies. Transmission providers should not be allowed to independently impose compliance obligations upon other parties. Any process to allow imposition of additional compliance responsibilities should be overseen by the appropriate regional reliability organization.
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
E.ON U.S. believes that the staggered implementation time tables for the various standard requirements could needlessly complicate initial compliance efforts. E ON U.S. requests that the SDT review these deadlines and standardize using the most lenient implementation period set forth in the current draft. E.ON U.S. recommends that the standard explicitly state in the purpose statement that voltage regulators be included in excitation system models. Voltage regulators are explicitly mentioned in R4.3 and R12. E.ON U.S. recommends that study data inputs and results only be made publicly available pursuant to Requirement 2. Depending on arrangements with vendors, actual model configuration may be proprietary and require confidential disclosure

arrangements
Group
FEUS
Clinton Jacobs
FEUS
Yes
Yes
Yes
Yes
No
No
No, This allows for ambiguity in the interpretation of the standard by both the entity and the requlator.
No
This leaves ambiguity in the standard that can be to misinterpretation by the entity or the agency. Some guidelines should be provided for standardization to avoid confusion.
Yes agree with approach and the 5% capacity factor
No, instead use the approach below:
If the modeling methods are approved and are valid, why do entities have to prove they are right? Test the models on several units of different sizes and configurations to determine their accuracy. If modeling methods aren't accurate, fix them instead of requiring the industry go through the huge expence of testing hundreds of units that have been previously modeled. I also don't see the rationale for the differences in MVA testing requirements between RRCs. The 200 MVA rating for facilities (as specified for the eastern systems) should be the same if this standard is adopted.
No
Yes, agree with proposed phase in period for unit excitation system verification
The excitation models as currently required are comprised of testing and data collection to determine the variables for the model parameters. How does additional testing, over and above what was done to construct the model, accomplish anything and how would it be any different than original testing to complete the model?
Individual
Jianmei Chai
Consumers Energy Company
No
Generator Owners and Generator Operators do not need or use an excitation system model. This model is properly owned by those who need and use it, i.e., the Transmission Planner or Transmission Owner. The Generator Owner should be responsible only for providing input data for the model. These data include such items as: - Manufacturer (and model, if available) and type of excitation system. - Rise times, reactances, time constants, gains, and saturation factors. - Rotational inertia - Reactive compensation settings, if any. - Power system stabilizer settings, if any. - Other stability schemes, if any. Given periodic verification of these data from the Generator Operator, it should be the responsibility of the Transmission Planner to create a model that meets the needs of the Transmission Planner. Since the Generator Operator doesn't need this model, requiring the Generator Operator to hire consultants to create a model needed by other entities is simply errant nonsense. Has the SDT verified that there are adequate consultants available to meet the 2-year time window for the myriad of Generator Operators who would be tasked with creating a model they do not need?
Yes
Ten years is appropriate with the caveats listed in Requirement 12.

Yes
This looks to be a "sister unit" type of proxy. If so, it should be introduced as a new definition.
Yes
We believe that generator data must be verified; however, the concept of staged tests is troubling as such testing can provide a local challenge to the integrity of the BES. Such testing should be required to be well coordinated with the Transmission Operator. Our experience shows start-up testing of new exciters has occasionally resulted in significant local impact to the transmission system, e.g., over-voltage on 345 kV systems.
No
No
It is the Transmission Operator and the Transmission Planner's task to determine if the model matches. The Generator Operator is uniquely unsuited to monitor transmission lines and determine if the model works. If the Transmission Planner's model doesn't properly reflect reality, the Transmission Planner should be required to meet with the Generator Operator and discuss the issue. The Generator Operator should then be required to reverify the data in question.
Yes
Providing minimal specificity allows many approaches to meet the requirements. This accommodates the many present and future excitation technologies and monitoring techniques.
No (disagree with approach)
We disagree with the approach. Some systems have very large peaking units which arguably are more likely to be in service on days when the BES would be challenged. Thus, modeling data should be collected for these units and model cases run including these data. Additionally, the requirement should only apply to peaking units which meet the applicability criteria (i.e. Capacity factor greater than 5% for the last 3 years and greater than the MVA indicated in 4.0)
Yes
We believe the MVA thresholds are appropriate and pick up the vast majority of interconnection (MVA).
No
No, the phase in period for unit excitation system verification should be (please specify below)
The phase-in period of 2 years is likely to be insufficient unless there are significantly more consultants available than we think there are, as many Generator Operators may need to hire a severely constricted resource.
N/A
N/A
It is our opinion that the SDT made a fundamental error in assigning the modeling to an entity that doesn't need the results of the model. To correct this error, this Standard needs very significant revision. As it stands, the Draft Standard imposes irrational requirements upon the Generator Operator.
Individual
Ben Johnson
Wisconsin Public Service
Yes
The Generator Owners, instead of Transmission Planners, are the logical entities to verify the proper functioning of the excitation system functions, but not the verifications of hypothetical parameter values of a model used to emulate the exciters' function. The generator Owners should, for example, verify that the AVR holds set terminal voltages under normal operating system conditions, as well as response to system changes in conformance with the stated Response Ratios as designed. This does not mean, however, that it would be necessary to confirm forward gains, transducer time constants, excitation saturation constants, feedback-loop gains and time constants, etc. are indeed of the same value as used in a hypothetical model. This is due to two reasons: 1) the particular model chosen by the transmission planner is known to be an approximation of the facilities' functions, and therefore the parameters are not unique; 2) instrumentations necessary for verification of specific parameters are not generally available in the industry.
Yes
No
The sister unit philosophy should be applied to identical units within a generator operators fleet with identical settings, but not be limited to the same physical site.

Yes
No
The model generally in use to simulate generator dynamic responses is a hypothetical model based on fictitious parameters. For instance, the direct-axis and quadratual-axis impedances are calculated design values, and not a measurable physical quantity, as are the transient and subtransient time constances. The inertial constance involve the whole rotor and prime-mover assembly, and cannot be easily quantified.
Yes
Yes
I agree with the methodology of the SDT to leave the test methods required under R4 out of the standard. It is a good philosophy to not limit future advancements in testing because the standard specifially calls for a step voltage test or UEL / OEL bumps. I think the SDT should consider this methodology in future drafts as applicable.
No (disagree with approach)
Threshold should be set around 20% to remove the requirements from those operators that may have a large fleet of small CT's that operate only in minimal peakng mode, but would qualify under the multiple units on the same site provision. These units have minimal impact on the dynamic model.
No, instead use the approach below:
The provisions of multiple generators at one location requiring testing of units above 20MVA rating puts too much ownerous on operators at CT sites with multiple small CT's that would act differently during an event and have minimal effect on the dynamic models.
Yes
Determined critical in the model or in a constrained area of the system.
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
At the Web-ex I thought the phase in was 10% per year with 100% by end of yr 11. This makes it sound like a different phase in will be used but no details on % at the 2, 6, and 11 year windows.
At plants with 200MW or higher capacity, it is unreasonable to assume multiple units of 20MW to malfunction simultaneously. Therefore, applying the standard to each unit of >/= 20MW if these are at the same contiguous plant of combined capacity of 200MW is placing unreasonable burden on owners of small generators. One must reason that, in the contest of the whole eastern interconnect, comprising a total capacity of 600,000MVA and higher, individual generators of less than 100MVA would not impact the system to any significant degree except for very localized regions.
Individual
Ronnie C. Hoeinghaus
City of Garland, Garland Power & Light - GOP Registered Entity
No
The Generator Owner (GO) should be responsible for model verification. The GO has direct access to the equipment - not the GOP. The GO can schedule any required operational testing with the GOP in the same way that the GO schedules any other operational testing requirement. In addition, the GOP and the GO can be two separate companies with their only relationship established by contract. In these situations this standard, as written, would place the burden on the GOP to try to renogoiate the contract with the GO to cover the expense and pursuade the GO to perform the model verification when the real responsibility belongs to the GO.
Yes
Yes
Yes
This same approach should be used for question #1. It is the Generator Owner (GO) that has this information and access to the equipment.
No
No

This should be the role of the Generator Owner (GO) - the GO has the data, the GO has the equipment, and the GO can schedule any required operational testing through the GOP.
Yes
Yes agree with the approach. But use another capacity factor (include supporting data):
Not sure which box to comment in: Strongly agree with your approach & reasons but believe that 10% should be the exemption level
Not sure which box to comment in: Strongly agree with your approach & reasons but believe that 10% should be the exemption level
Yes, agree with proposed phase in period for unit excitation system verification
Agree with both "Yes" statements - form will only allow one to be selected - if the 2 "Yes" statements are mutually exclusive, then I must not understand your statements & will go with the 1st "Yes"
Individual
Brendan Kirby
AWEA
Yes
Yes
Yes
Yes
No
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
No
There would have to be very clear technical justification for such a designation or it could be perceived as discriminatory and/or preferential
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
I agree with both the phase in period and allowing credit for units verified within the last 5 years via regional standards
Individual
Michael Goggin
American Wind Energy Association
No
Because Generator Operators typically do not have in-house expertise and would have to either hire consultants to perform model verification, or develop in-house expertise including acquiring simulation software, I think it makes more sense for Transmission Planners to perform this activity.
Yes

Yes
Yes
No
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
Yes
Yes, agree with proposed phase in period for unit excitation system verification
Group
Luminant Power
Rick Terrill
Generation Compliance
No
In ERCOT the Generation Owner should be responsible. This is a NERC Functional model issue, and I understand the GOP will be responsible in the majority of the country.
Yes
Yes
No
Luminant does not disagree that the information needs to be provided. However, the generator model data is already required in NERC Standards MOD-012 adn MOD-013 (R1.2). The Generation Owner should not be held doubly liable for the same informatin in two Standards. This requirement for the Generator data is already required elsewhere and is not needed in this standard.
No
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
No
The SDT is tasked with developing requirements for applicability across North America. Regions have the ability to develop more stringent requirements based on regional needs, and through various regional requirements development processes. Allowing the Transmission Planner or Planning Coordinator to expand the applicability of the NERC Standard on an individual resource basis (without industry input, balloting, etc.) would circumvent the FERC approved procedures for development of reliability standards.
Yes, agree with proposed phase in period for unit excitation system verification

Note that I also agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval. The form would not let me select both yes answers.
Possible regional variance on applicability with GOP vs. GO in ERCOT.
NA
NA
Individual
James H. Sorrels, Jr.
American Electric Power
No
AEP believes that It would be more appropriate to designate the Generator Owner for these responsibilities.
No
AEP believes that the period should be longer. In fact, verification should only need to be done once on older units that do not now have good commissioning test documentation. Beyond that, it should only need to be done if there is an applicable equipment upgrade or an intentional readjustment of settings. We question predicating the periodicity on the expectation of a significant variation in equipment performance due to aging alone.
No
While AEP agrees that the proxy approach to verify multiple, identical units based on system model verification for a single unit makes sense, it is unclear why criterion "b" (the units are rated at less than or equal to 250MVA) would apply, provided criteria "a", "c", and "d" are also met. It is suggested that criterion "b" as listed in the Comment Form and as referenced in Requirement R1.2 be removed from the Standard.
Yes
Yes
Generator parameters are needed to support modeling. Later phases could pick-up unknowns identified by examining discrepancies between actual operation and modeling.
No
AEP does not agree that the Generator Operator should not be responsible to provide documentation that the system model matches the recorded response. That responsibility should lie with the Generator Owner to review and decide how to have that analysis performed and to what extent documentation will be prepared to provide the required verification.
Yes
We are agreeable since there are different kinds of excitation systems.
No (disagree with approach)
Seldom run units could end up being run at peak times in areas that may be stability limited. Applicability should be driven by need for verification which historically, has been tied to stability performance and constraints.
No, instead use the approach below:
The need for excitation data and model verification has been driven by plant and system stability needs. We believe that the applicability in the standard should be driven by the same. We would go so far as to suggest that identification of applicable units should be determined by the TP and PC through a process that includes planning study results and operating experience, and that the standard should not specify a blanket applicability unrelated to the stability driven need.
Yes
Criteria should be units or plants whose operation is limited by transient or small-signal instability, or that are located in areas that may be subject to stability constraints. Why not rather impose the applicability in the fashion of what is being asked here, that the TP and PC identify through a process which units should be verified, not a blanket applicability as is in the current draft.
No, instead of allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date, instead would recommend (please specify below)
that the areas with the greatest instability be addressed first.
No known need for regional variances
CONFLICT: The added expense posed by the requirements of this standard must be sought through tariff changes with applicable regulatory authorities. COMMENTS: A strong cost-benefit analysis is required to receive the necessary cost recovery.
(1) The added expense to fulfill the requirements of this standard where such model verification is not generally being done could be high. Since this is a new imposition on the industry in that required excitation model verification has never before been imposed in many areas, this leads

to the question of cost versus reliability benefit of what is being proposed. We request that the SDT please comment more on the cost vs. reliability benefits. (2) With respect to R2, we suggest that it be revised and expanded as follows: "The Transmission Planner shall provide the Generator Operator a set of model data sheets for the acceptable excitation system models (models cannot be confidential or proprietary) for use in dynamic simulation software, with each data sheet including the excitation system model block diagram structure and data requirements and a system dynamics model, within 30 calendar days of a request from the Generator Operator." (3) With respect to R6, revise and expand the last sentence as follows: "If the TP determines the excitation system model is not useable, the TP shall provide the Generator Operator with a description of the problem and any relevant details, including the system dynamics case used in the evaluation." (4) With respect to last sentence in R9, revise and expand as follows, "â€¦. after the receipt of a request that includes the measured data following a system disturbance and a suitable system dynamics case associated with the system disturbance.
Group
Southwest Power Pool Generation Working Group
Edmundo Toro
Southwest Power Pool
Yes
Yes
Yes
No
The proposed standard states Generator Operator, as opposed to Generator Owner. The Generator Owner should be the one providing the data.
No
No
It is understood and agreed that many differing types of units and testing exist. With that thought in mind, it is felt the standard needs to provide some guidelines of how to perform the test and what type of test results are to be reported.
No
It is understood and agreed that many differing types of units and testing exist. With that thought in mind, it is felt the standard needs to provide some guidelines on how to perform the test and what type of test results are to be reported.
Yes agree with approach and the 5% capacity factor
No
Yes, agree with proposed phase in period for unit excitation system verification
The SPP Generation Working Group members have several concerns related to this standard. The skill-set required to perform these tests do not currently exist among Generator Owners and there is a great concern that the limited subset of consultants that will be able to perform this verification will not be able to complete these tasks within the suggested ten year period. Given the limited subset of parties that will perform these tests, the cost will be onerous on the Generator Owners while not providing significant benefits. SPP Generation Working Group members do not know of any issue that these enhanced requirements would have helped avoid and therefore see little value, given the potentially high cost, to these expanded requirements. SPP Generation Working Group members generally oppose the current version of this standard.
Individual
Baj Agrawal
Arizona Public Service Co.
Yes
Yes

Yes
Yes
No
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
No
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
The standard appears to be too unnecessary complicated. We have the following suggestion for simplification. 1)Requirements R1, R4, R11 and R12 are the only reliability related requirements and should be kept. 2)R8 is part of providing data and should be a part of R4 3)All other requirements are simply indicate process and do not belong in the standard. They should be part of a white paper on the subject or in an appendix.
Group
Exelon Corporation
David Schooley
Exelon Corporation
No
Exelon believes that model verification should be a coordinated effort between the generator owner and the transmission planner. Transmission planning organizations have the expertise to implement and test the models in software, while the generator owners have the necessary access to the equipment in the field. Most generator owners do not have the software and the necessary personnel with the expertise to perform the modeling and model testing required by this standard.
Yes
It is difficult to determine whether or not 10 years is an appropriate period for re-verification without knowing the details of the required testing.
No
Why there is a limitation of unit size of 250MVA or less. The proxy unit approach should be extended to identical units of any size for a two unit station as half of the capacity at that station has been verified as compared to a multi unit site say having 6 250MVAs and verifying only one unit.
Yes
No
Verification of the generator data will be useful, but needs to be considered at a later date.
No
Exelon feels that the standard should define the acceptance criteria. If the acceptance criteria is left up to the generator owners, then the TOs may have to deal with multiple acceptance criteria within a single region. At the same time, a single generator owner may have to work with multiple TOs, which will lead to inconsistency if the definition of the acceptance criteria is left up to the TO.
Yes
Yes agree with approach and the 5% capacity factor

Yes
Yes
Exelon is concerned about the use of the term "critical" in this context because it implies the same level of criticality that would be used to put a station on the critical asset list. A small generating station may be sufficiently close to another station that it affects the dynamic behavior of the generators at the second station. The Transmission Planner should be able to identify the units at the smaller station as applicable to the standard without calling them critical units. Exelon does appreciate the need for guidelines regarding the units that can be indentified as applicable to MOD-026.
Yes, agree with proposed phase in period for unit excitation system verification
The proposed standard and comment form presuppose the generator owners have the expertise necessary to model and simulate the excitiation systems on the units they own. They do not in most cases. Software requirements need to be considered. Not all transmission planners use the same software for dynamic simulations. A single generation owner may have units in multiple regions involving different transmission planners and would have to provide models for more than one simulation program. The standard needs to allow the Transmission Planner/Operator/Owner to provide expertise to the generator owner. The comment form and the WebEx meetings are more specific regarding software simulations than what is specified in the draft standard. The software simulations should be specified in more detail in the standard.
Individual
Dale Fredrickson
Wisconsin Electric
No
See response to Question 5. Providing model data and parameters is possible, but the requirement to validate the model for an actual switching event requires a cooperative effort between the GOP and the TP/TOP/TP. Since the stability and reliability of the overall transmission system is the goal, it is necessary for these entities to have more responsibility for proper excitation system modeling. As it stands this draft standard puts all the responsibility on the GOP.
Yes
No
We believe that units rated up to 850 MVA should be able to take advantage of this approach.
Yes
No
No
The requirements in R8 and R9 are not clear to us. The term "recorded response" needs to be defined, and the term "voltage excursion" needs to be quantified. These requirements infer that the GOP already has some documentation of what a "correct" response looks like, which is not the case. The requirement to validate the exciter model by monitoring its response to a real or staged event is not a simple matter. For a staged event such as switching a line, the TO or TOP will need to be actively involved in the process, and should have some responsibility assigned to it in the standard. Likewise, if an ambient switching event is used to validate the model, the TO/TOP would be the only entities in a position to know about it, since such operations may not be known by the GOP. In summary, this validation depends on shared responsibilities among the entities, and the requirements in this standard should properly reflect this.
Yes
Yes agree with approach and the 5% capacity factor
No, instead use the approach below:
In light of the size and density of the Eastern Interconnection, we are of the opinion that the MVA threshold for units should be raised to 150 MVA or higher.

No
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
Please consider the use of offline measurement of generator excitation response as a possible means to comply.
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
No
The Generator Operator does not have direct access to the equipment. The Generator Owner is the correct Functional Model entity that has direct access to the equipment and the authority to perform testing of equipment. All responsibilities assigned to the Generator Operator in the proposed standard should be reassigned to the Generator Owner.
Yes
A ten-year interval is acceptable given the conditions in Requirement R12.
No
Unit testing has in the past identified different responses from identical units with common settings. All units with identical design and settings should be tested unless records of actual system events demonstrate that all of the units respond the same.
Yes
The entity specified in Question 4 does not agree with the entity specified in Requirement R4. As stated in our response to Question 1, we believe the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.
No
Expanding the scope to include verification of generator data will not provide a significant improvement in the overall modeling of excitation systems.
No
As stated in our response to Question 1, we believe that the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.
Yes
Reliability Standards should focus on what is required and not how to meet the requirement. Further, it would be impractical to specify verification details universally applicable to all situations. The peer review process provides appropriate safeguards to ensure that appropriate methods are used for verification.
Yes agree with approach and the 5% capacity factor
We agree with this approach to exclude units with low capacity factors provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. Cases exist where large generating units with low capacity factors are operated only during the most stressed operating conditions. In such cases accurate modeling of these units may be critical to reliable operation of the bulk electric system.
Yes
We agree with the general approach to base the number and size of applicable generating units on the objective of validating models for 80 percent of the installed capacity on an Interconnection provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. In the event the Planning Coordinator or Transmission Planner is not permitted to identify additional units, the objective should be changed to validate models for a greater percentage of the installed capacity. We do not have data to verify whether the unit size thresholds specified in Requirement R4.1.1 correspond to 80 percent of the installed capacity on an interconnection, and respectfully suggest that it is the responsibility of the SDT to provide such verification.
Yes
The Planning Coordinator or Transmission Planner should be permitted to identify additional units

for applicability of the Standard based on the results of generator interconnection studies or other studies that demonstrate the criticality of correct settings on system reliability, e.g. studies demonstrating sensitivity of a stability based System Operating Limit to correct equipment settings and functionality.
No, the phase in period for unit excitation system verification should be (please specify below)
The proposed impmentation plan is too long. We recommend a five-year implementation with a requirement that units representing 20 percent of installed capacity be tested each year. We are concerned that an eleven-year implementation plan does not adequeately promote system reliability, and that having only three milestones will place a burden on system operators to schedule testing because Genator Owners may wait until years two, six, and eleven to schedule testing instead of spreading the tests out over the implementation period. The form will not accept more than one box checked above, but "Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date" should be checked.
None.
None.
No.
Group
Constellation Power Generation & Constellation Nuclear
Scott Etnoyer
Constellation Power Generation
Yes
Yes
Yes
The proxy unit approach is quite appropriate for excitation system verification for multiple units.
Yes
No
Expanding the scope to include verification of generator data will not provide any significant improvement in the modeling of excitation systems.
No
Yes
Yes agree with the approach. But use another capacity factor (include supporting data):
Yes
We agree with the general approach to base the number and size of applicable generating units on the objective of validating models for 80 percent of the installed capacity on an Interconnection provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. In the event the Planning Coordinator or Transmission Planner is not permitted to identify additional units, the objective should be changed to validate models for a greater percentage of the installed capacity. We do not have data to verify whether the unit size thresholds specified in Requirement R4.1.1 correspond to 80 percent of the installed capacity on an interconnection, and respectfully suggest that it is the responsibility of the SDT to provide such verification.
Yes
The Planning Coordinator or Transmission Planner should be permitted to identify additional units for applicability of the Standard based on the results of generator interconnection studies or other studies that demonstrate the criticality of correct settings on system reliability, e.g. studies demonstrating sensitivity of a stability based System Operating Limit to correct equipment settings and functionality.
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
None.
None.
The standard needs to clarify what verification of excitation system model entails; does this involve testing of excitation parameters? Online or offline. On line testing of excitation

parameters will present an unacceptable tripping risk to nuclear units. Recommend nuclear units be exempt from excitation system model verification if it involves online testing.
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
Yes
Yes
Yes
No
Yes
This should be done in consultation with planning/operating studies groups, since invariably these groups possess the necessary expertise and are in a better position to adjust/modify the model.
Yes
Yes agree with approach and the 5% capacity factor
Low capacity factor units such as wind turbines which could be part of a large MVA rated farm, should be in a separate category.
Yes
No
Yes, agree with proposed phase in period for unit excitation system verification
none
none
The MOD-026 Standard uses different terminiology in two different places. In requirement 4, the fourth bullet uses the term Reactive compensation and in Requirement 12, the fourth bullet uses impedance compensator. Either term is fine to use, but should be consistent throughout the standard.
Individual
D. Bryan Guy
Progress Energy, Inc.
No
The Generator Owner is the correct entity for this responsibility. It must be the entity that would be the most able to obtain the attention of the manufacuturer and have the means to accomplish the validation. The entity must have the financial incentives to perform the function and must be knowledgable about the plant operation. The entitiy that would be the best source to coordinate the testing could be required to verify the models. In our opinion the functional model specifies Generator Owner as it requires a generator owner to "verify generating facility performance characteristics". For the foregoing reasons this responsibility should not be assigned to the Transmission Planner.
Yes
As long as there is a requirement such as R11. The second bullet of R11 might also note that the Generation Operator must verify for the model for the first time if the model was derived from a 'sister' unit or repeat the verification on one previously verified. Despite R12, some communication between the Generation Operator and the Transmission Operator within the 10 year period would be reassuring that nothing has changed. Because ten years is a long time, the Generator Owner should be required to respond upon request of the Transmission Planner confirming that nothing has changed.
No
We encourage the proxy unit approach. However, we do not agree completely to the conditions illustrating proxy unit approach. (1) MVA rating should be expanded to say "MVA nameplate rating" . We believe it would be prudent to specify that units of different manuafacturers, even if they have the same nameplate rating are not proxy units, (2) If the units are identical, we

believe the 250 MVA threshold criterion is too restrictive. We believe the limit should be at least 350 MVA to cover combined cycle units of existing technology.
Yes
Since the exciter model and the generator model are components of the closed loop system being verified, the process must ensure that the Transmission Planners dynamic database is updated with the generator data and the excitation system data utilized for verification. Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunties for generator data submitted for MOD-012 to be inconsistent with generator data used in models in the excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator the unit specific data contained in the Transmission Plannerâ€™s dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was changed in order to obtain a verified excitation system model". These language modifications ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.
No
To include generator data verfication beyond excitation system modeling data is a significant burden to the Generation Owner not supported by the benefits to be gained.
Yes
The functional model entity responsible for the model's verification has to be given the responsibility of demonstrating that the provided model's response matches the recorded response. The "goodness of fit" between the model response and the equipment response should be left to the generator owner but subject to Transmission Planner review ref. R10.
Yes
We agree with the SDT approach of not developing this standard like a technology specific procedural manual. The development of verification Requirements stating "what is required" and leaving the technical details up to the personnel performing the verification will result in improved dynamic models while affording sufficient technical latitude.
No (disagree with approach)
The 5% capacity factor is an inappropriate basis for an exemption since it would allow significant blocks of generation (i.e. plants of several hundred MW) to be exempt. Such amounts of generation may have a significant impact on the stability of nearby generating units or such units may themselves have stability issues that need to be understood via valid studies. Examples would be plants with multiple combustion turbine units (particularly simple cycle oil burners) that are rarely run. However, when they are run (i.e. during peak system load times), the grid may be already be stressed and operating with reduced stability margin. The possibility also exists that while the exempted generation may have a capacity factor of less than 5%, this could quickly change due to unanticipated system conditions or the extended unavailability of other generation (due to severe damage for example). Therefore, the subject generating units could end up being run for a significant length of time without the benefit of having been properly analyzed by the Transmission Planning organization. The â€œaverage over the last three calendar yearsâ€ methodology further contributes to this possibility, introducing a time lag in the process. Based on the above discussion, the 5% capacity factor exemption should only be allowed when it would not be expected to significantly impact the results of stability studies. Allowing the Transmission Planner to make this judgement is most appropriate since A) that organization is in the best position to make the determination of the impact on stability and B) that organization is responsible (via TPL standards) for ensuring the stability of the grid and connected generating units. In lieu of the blanket 5% exemption, the following is proposed. 1. Delete â€œâ€¦ and with an average Capacity Factor of greater than 5% over the last three calendar yearsâ€ in all places in 4.1.1.1, 4.1.1.2 and 4.1.1.3 2. Add new Applicabilty 4.1.1.4 stating â€œGenerating facilities with capacity factors less than 5% over the last three calendar years may be exempted with written concurrence from the applicable Transmission Planning Authority. The written concurrence provided by the Transmission Planning Authority shall include the basis for any such exemptions.â€ alternative to (2.) could be the reponse to Q9 below.
Yes
However, the MVA values MUST be coordinated with the MVA thresholds in MOD-010 to 012 and in proposed TPL-001 standards. Supporting data (circa 2003) can be found from the link below which provides a spread sheet titled â€œExisting Generating Units in the United States by State, Company and Plant, 2003.â€ http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/gu_tabs.html
Yes

Add to Applicability a 4.1.1.4 stating â€œGenerating facilities that do not meet the applicability requirements 4.1.1.1 - .3 may be included when their performance is found to create or contribute to reduced reliability of the BES when requested by the applicable Transmission Planning Authority. The written request provided by the Transmission Planning Authority shall include the technical basis for any such inclusion (e.g. must run for reliability, voltage, or stability needs).â€
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
The first time period should be 3 years (10%). It is anticipated that the first units will take significantly longer than subsequent testing. Although this factor is already being considered in proposed time periods, there will probably be a significant shortage of testing services at the beginning of the testing window.
No.
No.
Requirement 1 Item 1) should be clarified to state that "new equipment commissioning date" applies to modifications of existing units. Requirement numbering for R1, R4, R5, R7-12 needs to be revised to conform to proper format.
Individual
Greg Mason
Dynegy
No
The Generator Owner does not need or use an excitation system model. The Transmission Planner is the entity that uses and needs this model to be accurate. The Generator Owner should be responsible for collecting and providing the generator related input data forthe model to the Transmission Planner. The Transmission Planner should be responsible for running the simulations required for model verification and making the judgement if the model's response matches the actual response.
Yes
Yes
Yes
No
No
See response to Item #1.
Yes
Yes agree with approach and the 5% capacity factor
Yes
We support SDT's approach to include aggregate MVA values. We also would like to suggest minor wording changes for SDT consideration to revise the language in the draft standard to better reflect an aggregate MVA approach. The word "same" is added to draft standard language as following: " Each unit (including synchronous generators) => 100 MVA, connected at the SAME point of interconnection at 100 Kv or above and with an â€¦â€¦".
No
No, the phase in period for unit excitation system verification should be (please specify below)
If the Generator Owner is assigned the responsibility for model verification, there will not be enough consultants to handle the resulting workload placed on Generator Owners.
None at this time.
None at this time.
None at this time.
Individual
Rick White
Northeast Utilities
No
The Generator Owner is the correct Functional Model entity that has direct access to the

equipment and the authority to perform testing of equipment. All responsibilities assigned to the Generator Operator in the proposed standard should be reassigned to the Generator Owner.

Yes

Consider the need to account for wind turbine generation that does not have mature models for this verification - therefore a shorter period may apply to accommodate improvements of those models.

No

Units testing has in the past identified different responses from identical units with common settings. All units with identical design and settings should be tested unless records of actual system events demonstrate that all of the units respond the same.

Yes

The entity specified in Question 4 does not agree with the entity specified in Requirement R4. As stated in our response to Question 1, we believe the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.

Yes

Consider model verification for rotational inertia, which can have a significant effect on modelling.

No

As stated in our response to Question 1, we believe that the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity. Agree that peer review by TP/PC is important for verifying the match.

Yes

Yes agree with approach and the 5% capacity factor

Yes

Yes

No, the phase in period for unit excitation system verification should be (please specify below)

We recommend a five or ten-year implementation with a requirement that units representing 20 or 10 percent, respectively, of installed capacity be tested each year. We are concerned that having only three milestones will place a burden on system operators to schedule testing because Genator Owners may wait until years two, six, and eleven to schedule testing instead of spreading the tests out over the implementation period.

Group

SERC Dynamics Review Subcommittee (DRS)

Rick Foster

Ameren Services

No

The Generator Owner is the correct entity for this responsibility. It should be the entity that would be able to obtain the attention of the manufacuturer and have the means to accomplish the validation. The entity should have the financial incentives to perform the function and should be knowledgable about the plant operation. The entitiy that would be the best resource to coordinate the testing should be required to verify the models. In our opinion the functional model specifies the Generator Owner as it requires a generator owner to "verify generating facility performance characteristics". For the foregoing reasons this responsibility should not be assigned to the Transmission Planner.

Yes

We agree as long as there is a requirement such as R11. The second bullet of R11 might also note that the Generation Operator (Owner) must verify the model for the first time if the model was derived from a 'sister' unit or repeat the verification on one previously verified. Despite R12, some communication between the Generation Operator (Owner) and the Transmission Operator, within the 10 year period stating that nothing has changed would be reassuring. Because 10 years is a long time, the Generator Owner should be required to respond if requested by the Transmission Planner confirming that nothing has changed.

No

We encourage the proxy unit approach. However, we do not agree completely to the conditions illustrating the proxy unit approach. (1) "MVA rating" should be changed to say "MVA nameplate rating". We believe it would be prudent to specify that units of different manuafacturers are not proxy units, even if they have the same nameplate rating, (2) If the units are identical, we believe the 250 MVA threshold criterion is too restrictive. We believe the threshold should be at least 350 MVA to cover combined cycle units using existing technology.
Yes
Since the exciter model and the generator model are components of the closed loop system being verified, the process should ensure that the transmission planners dynamic database is updated with the generator data and the excitation system data utilized for model verification. Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunties for generator data submitted for MOD-012 to be inconsistent with generator data used in the excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator with the unit-specific data contained in the Transmission Plannerâ€™s dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was changed in order to obtain a verified excitation system model". These language modifications will help ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.
No
Yes
The entity responsible for the model's verification has to be given the responsibility of demonstrating that the model's response matches the recorded response. The "goodness of fit" between the model response and the recorded response should be left to the generator owner but subject to Transmission Planner review ref. R10.
Yes
We agree with the SDT approach of not writing this standard like a technology specific procedural manual. The development of verification Requirements stating "what is required" and leaving the technical details up to the personnel performing the verification will result in improved dynamic models while affording sufficient technical latitude.
No (disagree with approach)
The 5% capacity factor is an inappropriate basis for an exemption criteria since it would allow significant blocks of generation (i.e. plants of several hundred MW) to be exempt. Units in this class of generation may have a significant impact on the stability of nearby generating units or may have stability issues that need to be understood via valid studies. Examples would be plants with multiple combustion turbine units (particularly simple cycle oil burners) that are rarely generating. However, when they are generating (i.e. during peak system load times), the grid may be already be stressed and operating with a reduced stability margin. The possibility also exists that while the exempted generation may have a historical capacity factor of less than 5%, this could quickly change due to unanticipated system conditions or the extended unavailability of other generation (due to severe damage for example). Therefore, the subject generating units could generate for a significant length of time without the benefit of having been properly analyzed by the Transmission Planning organization. The â€œaverage over the last three calendar yearsâ€ methodology further contributes to this possibility, introducing a time lag in the process.
Based on the above discussion, the 5% capacity factor exemption should only be allowed when it would significantly impact the results of stability studies. Allowing the Transmission Planner to make this judgement is most appropriate since A) this entity is in the best position to make the determination of the impact on stability and B) this entity is responsible (via TPL standards) for ensuring the stability of the grid and connected generating units. In lieu of the blanket 5% exemption, the following is proposed. 1. Delete â€œâ€¦ and with an average Capacity Factor of greater than 5% over the last three calendar yearsâ€ in all places in 4.1.1.1, 4.1.1.2 and 4.1.1.3 2. Add a new section under Applicabilty 4.1.1.4 stating â€œGenerating facilities with capacity factors less than 5% over the last three calendar years may be exempted with written concurrence from the applicable Transmission Planning Authority. The written concurrence provided by the Transmission Planning Authority shall include the basis for any such exemptions.â€ alternative to (2.) could be the reponse to Q9 below.
Yes
The MVA values should be coordinated with the MVA thresholds in MOD-10 to MOD-12 and in proposed TPL-001 standards. Supporting data (circa 2003) can be found from the link below which provides a spreadsheet titled â€œExisting Generating Units in the United States by State,

Company and Plant, 2003.â€ http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/gu_tabs.html This spreadsheet can be sorted and summed to get an estimate of the percentage generation that would be included. A preliminary look by the DRS suggests that 80% or more would be included.
No
Add a new section under Applicability 4.1.1.5 stating â€œGenerating facilities that do not meet the applicability requirements of 4.1.1.1 - .4 may be included when their performance is found to reduce the reliability of the BES by the applicable Transmission Planning Authority. A written request provided by the Transmission Planning Authority shall include the technical basis for any such inclusion (e.g. must run, reliability, voltage, or stability needs).â€
No, the phase in period for unit excitation system verification should be (please specify below)
The first time period should be 3 years (10%). It is anticipated that testing of the first units will take significantly longer than subsequent testing. Although this factor may have been considered in the proposed time periods, other factors such as the potential shortage of testing services at the beginning of the testing window may not have been considered.
Requirement 1 says testing should occur "for new or existing units within 180 days of commerical operation". We believe the testing should be done before commerical operation.
Group
Dominion
Jalal Babik
Dominion Resources Services, Inc.
No
In general, there should be collaborations between the Generator Owner, Transmission Planner, Generator Operator, and Transmission Operator to meet the intent of model and data verification. However, the requirements of this standard should apply to the Generator Owner and the Transmission Planner. We have reviewed the NERC Functional Model and believe that the Generation Owner should be responsible for those requirements assigned to the Generator Operator in this draft standard. We are concerned that Generator Owners may have to acquire outside sources or develop in-house skills in order to meet the requirements of this standard. However, we feel that the proposed effective date(s) allows adequate time to address these concerns.
Yes
Yes
Yes
We believe that all requirements of this standard should apply to the Generator Owner, not the Generator Operator.
No
MOD-024 and MOD-025 address a generator's real and reactive capability verification and MOD-026 addresses the excitation system verification. It seems desirable to have a MOD standard that address the verification of generator data by the Generator Owner (not the Generator Operator). This can be handled by a new SAR since the scope change of the current SAR could delay the process. In scoping the verification of the generator dynamic data: a) If the existing generator dynamic model data is backed by documentation provided by the generator manufacturer or previous test(however old it is), no verification would be required. b) If there is no documentation (from manufacturer or previous test) supporting the existing generator dynamic model data, saturation, inertia & D-axis parameters (time constants and impedances) have to be verified at the minimum. If the measured D-axis parameters show reasonable agreement with the existing generator dynamic data, it is not required to verify the Q-axis parameters; otherwise the Q-axis parameters need to be verified as well.
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
The proposed threshold captures at least 80.5% of the generators owned by Dominion.

Yes
If a unit exhibits transient or dynamic instability for an event but the simulation did not show the same then the excitation system shall be tested for units beyond those specified section 4.1.1.
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
SERC - supplement requires members to validate the excitation system model parameters of their generating units within 7 years (dated 2007). MRO â€“draft guideline in field test, not currently in effect.
The SDT should define exactly what the "excitation model" means. At a minimum it should include the AVR, exciter, PSS (if installed) and voltage compensator (if installed). The current document appears to imply that the minimum and maximum excitation limiters (if installed) are not part of the "excitation model." 2. We are concerned that, in order to meet this standard, applicable entities may have to share data and software that may be proprietary and which may vary depending upon vendor(s) selected by the Transmission Planner. R2 states that â€œmodels cannot be confidential or proprietaryâ€. 3. We believe that applicabilty section should be modified so that it only includes entity(ies) defined in the NERC Functional Model. At 4.1.1 it states â€œGenerator Operators of generating facilities:â€ We believe it should state Generator Owner (the term used in functional model). a. We can support 4.1.1.1 if the language is revised to read â€œWith generators that are connected to Eastern or Quebec Interconnections with the following characteristicsâ€¦â€¦â€¦â€¦â€¦â€ 4. The requirement R2 should be restated to read: The Transmission Planner shall provide the Generator Owner a set of model data sheets for the standard (as opposed to acceptable)excitation system models for use in dynamic simulation software, with each data sheet including the excitation system model block diagram structure and data requirements, within 30 calendar days of a request from the Generator Owner. If the excitation system characteristic is such that it cannot be represented by one of the Standard models, the Generator Owner shall be obligated to have a user-written model developed and made it available to Transmission Planner for use in the dynamic simulation software used by the Transmission Planner.
Individual
Tom Bradish
Reliant Energy
Yes
Unit operation not unit ownership impacts the reliability of the grid.
No
The period for re-verification should be based on observed performance, by activities that could result in an alteration of equipment performance or as listed in Requirement R11 which could trigger a review includes Plant Digital Control System (DCS) additions, replacements, or software alterations. Plant DCS activities would only be relevant to excitation system modifications if they involved the addition, deletion, or modification of an outer loop control (such as power factor or reactive power set point) that alters automatic voltage regulator action. If it ain't broke don't fix it!
Yes
I can not see any reliability benefit to requiring the verification of sister units.
Yes
But to be consistant I think it should be the GOP not the GO.
No
No
It should be the TP working with the GOP.
Yes
I susgest that the SDT consider a white paper expounding how the verification can be performed.
Yes agree with approach and the 5% capacity factor
Yes
The SDT at least has done an engineering analysis in developing the MVA thresholds. I am not sure that registration criteria was done in the same manner.
Yes
Units that have an RMR. If they do not have an RMR (in unorganized markets) then how can they be called critical?

Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
Individual
Patrick Farrell
Southern California Edison
Yes
Yes
Yes
Yes
No
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
No
Yes, agree with proposed phase in period for unit excitation system verification
Group
Southern Company
Hugh Francis
Southern Company Services, Inc.
No
The Generator Owner appears to be the logical choice. GO has the access to the equipment records, GOP may not.
Yes
Years of operating experience has shown that existing excitation systems that are properly maintained typically do not deteriorate to the point where performance is noticeably impacted in less than 10 years.
No
Agree with all requirements except b and d. If the GO/GOP has duplicate units at multiple sites , a re-verification test of one unit should apply to all provided they meet items a and c. The size of the unit (b) nor the physical location (d) do not matter. The MVA rating of the machine should not be an excluding factor for units of the same vintage, rating, manufacturer, and with the same type of excitation system and settings.
No
Since the exciter model and the generator model are components of the closed loop system being verified, the process should ensure that the transmission planners dynamic database is updated with the generator data and the excitation system data utilized for model verification. Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunities for generator data submitted for MOD-012 to be inconsistent with generator data used in the

excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator with the unit specific data contained in the Transmission Plannerâ€™s dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was updated during the process of obtaining a verified excitation system model". These language modifications will help ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.
No
As a general rule the industry has not demonstrated a need to validate OEM supplied generator data.
Yes
Yes
Yes agree with approach and the 5% capacity factor
The idea that this standard should not be applicable to low capacity factor seems perferable. However, 5% capacity factor may be too high. For instance, there are 8760 hours in a year. A 5 % capacity factor could mean a unit running its at nameplate MW for 438 hours. Or, it could mean more than 438 hours if the unit is not running at its nameplate all the time when running. For Southern Company Generation, the current criteria would result in the standard applying to at least 80% of our generation capacity.
Yes
See comment on 7 above.
No
Yes, agree with proposed phase in period for unit excitation system verification
We agree with both Yes statements above. The software will only allow one to be marked.
Paragraph 4.1.1.1 3rd Section: The plant criteria should be assessed on a switchyard basis instead of all inclusive. For example: 5 unit station with 4 units > 100 MVA each connected at 500 kV and one unit <50 MVA connected at 115 kV. Why do I need to do the small unit? Paragraph R1.2: See discussion in question 3 above regarding the criterion of 'sited at the same physical location and MVA ratings.' We see no need for these restrictions. Paragraph R7: A third option is to do more testing/technical assessment with a longer time allowed (>90 days) should be included. Paragraph R8: The last part of this requirement is unclear: 'â€¦within 90 calender days â€¦. verification.' Change the wording from 90 calendar days of competion to 90 calendar days after completion. The requirement will than read, " The Generator Operator shall provide to the Transmission Planner documentation demonstrating that the excitation's system model's response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) within 90 calendar days after completion of the excitation system model verification." Paragraph R12: The second and third bullets should be combined to cover any DCS/AVR inter-actions.
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
IMPA recognizes that the Generator Operator can work with the Transmission Planner when it comes to using the verified data in a proper model or simulation software program. This assistance from the Transmission Planner might mean that the Generator Operator does not need to purchase modeling software.
Yes
Yes
No
IMPA believes the generator data is important and that it is currently being provided per MOD-010 (static) and MOD-012 (dynamic). Another standard requiring this information would put the

stakeholder at a double risk factor, and FERC does not believe in this double risk factor.

No

Yes

Yes

Yes agree with approach and the 5% capacity factor

A small utility owns a GE 7EA Turbine/Generator with a nameplate rating of 101 MVA in the Eastern Interconnection. The utility uses it as a peaking unit and the capacity factor for the unit averages less than five percent over the last three years. Obviously, this unit does not play a vitale role in maintaining the reliability of the BES. Therefore, why make this utility spend thousands of dollars on testing a machine that is not important to reliability. By using a capacity factor of 5%, this unit will be exempt from this standard.

Yes

No

Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date

IMPA is concerned about the implementation plan. The 10 percent in two years seems feasible, but what if companies decide to test all their units to save on travel cost of a contractor. Has the SDT looked at the total number of units that are covered by this standard and how many contractors can do this work? For example, if a company owns five or more peaking units in one location or in close proximity, they may decide to test all their units at the same time and pay for only one trip by the contractor. Then the next Generator Operator does the same with its units and this continues to occur throughout the two year time period. This type of mentality may hurt the Generator Operator who owns only one unit and has to wait on an available contractor to perform the test. If the Generator Operator does not get that one unit tested within the first two years, it will be non-compliant with this standard (the Generator Operator only owns one unit that this standard applies).

Group

Kansas City Power & Light

Don Brown

Kansas City Power & Light

Yes

No

The Electric Power Research Institute has issued a report, "Power Plant Modeling and Parameter Derivation for Power System Studies", number 1015241, Final Report, June 2007; a reasonable interpretation of that work is that there may not be sufficient benefits from using a highly complex model to overcome the potential risks of the testing needed to verify the most complex models. Prototype test data obtained by manufacturers to provide the initial data, in many cases, simply can not be duplicated on operating / operational equipment. The 10 year re-verification requirement, as presently written, does not appear to allow generator owners the necessary flexibility to determine, similar to the regulatory model of 10 CFR 50.59 "Changes, Tests, and Experiments", how detailed the "re-verification" activities need to be. The requirement to re-perform the same bank of physical tests used to originally validate the generator model, absent a physical modification, does not allow sufficient flexibility to perform only those "re-verification" activities for those model parameters whose change due equipment aging has discernable effect on the outcome of the analysis using the generator model. Please note that the concern for performance of tests with little discernable analytical benefit was previously voiced in the "MAAC Position Paper on Generator Testing to Verify Data Required for System Modeling" in the Phase III-IV Planning Standards comments, which can be found on the NERC www site, where the issue of testing nuclear units in compliance with the regulatory requirements of 10 CFR 50.59 was also noted. As a result, it is recommended the SDT consider removing all references in the requirements for periodic testing when no physical changes have taken place and clarify R12 reflects to reverify the parts of the modeling affected by a change and not a reverification of the entire model. In addition, although the reason to verify generator modeling is logical, it is

requested the SDT consider the references stated above and consider the removal or modification of requirements involving testing that place an unncessary risk of generator damage. As an example, allowing vendor simulations or other testing methods by the Vendor in a suitable testing environment to suffice for obtaining generator response characteristics.
Yes
Yes
No
There are clearly benefits to having as much verified operational characteristic data as possible, however, as previously noted in response to question #2, the equipment risks associated with obtaining those benefits should be a consideration. Considering an aging generation infrastructure, the risk of obtaining parts for equipment damaged in the pursuit of modeling verification can be extremely costly in extended downtime and the availability of parts is also a concern. Again, it is recommended the SDT consider the removal or modification of requirements involving testing that place an unncessary risk of generator damage. As an example, allowing vendor simulations or other testing methods by the generator Vendor in a suitable testing environment to suffice for obtaining generator response characteristics.
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
Yes
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
Not aware of any regional differences.
Not aware of any conflicts.
Where specific codes and standards are referenced as either the technical basis for, or an acceptable means to comply with the NERC requirements, such as IEEE 421 referenced directly in Draft 1 of MOD-026-1, or IEEE 1110 and IEEE 415, please clarify these are references only and the content of these references in no way add to the requirements proposed here.
Individual
Kathleen Goodman
ISO New England Inc.
No
The Generator Operator has the greatest ability to develop and/or provide accurate models and model parameters for its equipment. The Generator Owner should also be involved in the verification process as required. The process should ideally allow interations between the GO and TO to allow for needed adjustments to model compatability issues and settings with the GO, It should be field verified data not just a self certification of data without the field verification.
No
We recommend validation on a 5 year scale. 10 years is too long if changes are made to settings during annual outages. The whole approach of the draft standard is a bit flawed because once the model and tuned parameters are verified, no control setting changes should be made to the physical equipment without consulting with the TO to determine their acceptability. Additionally, updates should be provided if the manufacturer or GO identify improvements to the model in regard to matching the actual equipment. Having a verification in addition to the preceding is acceptable and would provide the benefit of having a written documentation from the GO and better assure that acccurate models are being used for planning the system.
Yes
Yes
No
Manufacturer's estimates of generator characteristics appear to be generally accuracte and

relatively easy to obtain.
No
The generator should provide the data to Reliability Coordinators, Transmission Operators and Planning Coordinators for verification. Generator Owners should provide factory models for excitation systems to Reliability Coordinators, Transmission Operators and Planning Coordinators and these models should be verified with the field data.
No
This may lead to "weak" submittals from certain entities.
No (disagree with approach)
These low capacity factor units may be critical during peak conditions and are almost certain to be older units that have the least accurate factory excitation system models. It is felt that having accurate models for these older units is required. Generators under 100 MVA make up about 15% of capacity in New England. Excluding low capacity factor large units may exclude more than 20% of the generators from model verification.
Yes
Currently generators over 100 MVA make up about 85% of the installed generator capacity in New England. Concentration on these units should provide an accurate representation of the system. Efforts to verify lower MVA capacity units would provide limited benefit for the work involved.
No, the phase in period for unit excitation system verification should be (please specify below)
2-1/2 years with a 5 year overall renewal of verification.
Group
MRO NERC Standards Review Subcommittee
Michael Brytowski
MRO
No
To help differentiate the BES model from the unit specific excitation system model. The MRO NSRS suggests a change in R1 to read; "The Generator Operator shall verify their applicable excitation control system modelâ€¦"
Yes
Yes
Yes
No
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
No
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
No
No

Individual
Kirit Shah
Ameren
No
(1)Generator Operators and Generator Owners both should be included in this standard. The entitiy that would be the best source to coordinate the testing could be required to verify the models. It is possible that all functions can not be performed by the Generator Operator alone. Therefore it would be prudent to include the Generator Owners within MOD-026-1. (2) Additionally, the GO would be able to obtain the attention of the manufacuturer than GOP. In our opinion the functional model specifies Generator Owner as it requires a generator owner to "verify generating facility performance characteristics". In any case, this responsibility should not be assigned to the Transmission Planner. (3) On the other hand, GO/GOP should not perform the function of modeling or verifying dynamic simulations on the Bulk Electric System which generally is done by Transmission Planners. Generator Operators/Generator Owners should provide the data needed for model simulation. Generator Operators/Generator Owners do not possess the expertise or have the resources to perform modeling simulations.
No
(1) Many generating units are now on six year outage cycles, therefore we recommend the interval is changed to 12 years or more. (2) Concerns regarding excitation equipment are that someone at the plant may inadvertently modify settings on dials/potentiometers at some point within a 10/12 year period (or other interval that would be considered appropriate) that would cause the performance of the exciter to vary from what was originally specified in the dynamic model representation. Also, it is possible that, through aging, electrical values of circuit components in the excitation equipment could drift, even with no external change to the settings. It is uncertain what the re-verification period should be to minimize these effects, so we support the caveats listed in Requirement 11 and 12. However, despite R12, some communication between the Generation Operator and the Transmission Operator within the 10/12 year period would be reassuring that nothing has changed. Because 10/12 years is a long time, the Generator Owner should be required to respond upon request of the Transmission Planner confirming that nothing has changed. Further, the second bullet of R11 might also note that the Generation Operator must verify for the model for the first time if the model was derived from a 'sister' unit or repeat the verification on one previously verified.
Yes
We encourage the proxy unit approach. However, we do not agree completely to the conditions illustrating proxy unit approach. (1) MVA rating should be expanded to say "MVA nameplate rating" . We believe it would be prudent to specify that units of different manuafacturers, even if they have the same nameplate rating are not proxy units. Further, turbine rating should also be considered as appropriate. (2) If the units are identical, we believe the 250 MVA threshold criterion is too restrictive. We believe the limit should be at least 350 MVA to cover combined cycle units of existing technology.
Yes
(1) Generator Operators and Generator Owners should be included in this standard. It is possible that all functions can not be performed by the Generator Operator. Therefore it would be prudent to include the Generator Owners within MOD-026-1. (2) If the generator has not been modified, and the manufacturer's data is available, then there should be no need for retesting of the generator. However, if the generator has been modified since the last data set was established for the generator, (stator or rotor turns shorted, rotor replaced, etc.) then re-testing of the generator would be in order. If the turbine has been replaced, then an updated value for rotational inertia would be needed. (3) The concept of staged tests is troubling as such testing can provide a local challenge to the integrity of the BES. Such testing should be required to be well coordinated with the Transmission Operator. (4) Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunties for generator data submitted for MOD-012 to be inconsistent with generator data used in models in the excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator the unit specific data contained in the Transmission Plannerâ€™s dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was changed in order to obtain a verified excitation system model". These language modifications ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.
No
None

No
(1) Generator Operators and Generator Owners should be included in this standard. It is possible that all functions can not be performed by the Generator Operator. Therefore it would be prudent to include the Generator Owners within MOD-026-1. The Generator Operator or Generator Owner should verify the model but should not be responsible for the model. (2) No issues with peer-to peer review, as this would help drive what are necessary and sufficient conditions for matching the responses. (3) The functional model entity responsible for the model's verification has to be given the responsibility of demonstrating that the provided model's response matches the recorded response. The "goodness of fit" between the model response and the equipment response should be left to the generator owner but subject to Transmission Planner review ref. R10.
Yes
We agree with the SDT approach of not developing this standard like a technology specific procedural manual. The development of verification Requirements stating "what is required" and leaving the technical details up to the personnel performing the verification will result in improved dynamic models while affording sufficient technical latitude.
No (disagree with approach)
(1) Some systems have very large peaking units which arguably are more likely to be in service on days when the BES would be challenged. Thus, modeling data should be collected for these units and model cases run including these data. (2) The 5% capacity factor is an inappropriate basis for an exemption since it would allow significant blocks of generation (i.e. plants of several hundred MW) to be exempt. Such amounts of generation may have a significant impact on the stability of nearby generating units or such units may themselves have stability issues that need to be understood via valid studies. Examples would be plants with multiple combustion turbine units (particularly simple cycle oil burners) that are rarely run. However, when they are run (i.e. during peak system load times), the grid may be already be stressed and operating with reduced stability margin. (3) The possibility also exists that while the exempted generation may have a capacity factor of less than 5%, this could quickly change due to unanticipated system conditions or the extended unavailability of other generation (due to severe damage for example). Therefore, the subject generating units could end up being run for a significant length of time without the benefit of having been properly analyzed by the Transmission Planning organization. The â€œaverage over the last three calendar yearsâ€ methodology further contributes to this possibility, introducing a time lag in the process. Based on the above discussion, the 5% capacity factor exemption should only be allowed when it would not be expected to significantly impact the results of stability studies. Allowing the Transmission Planner to make this judgement is most appropriate since A) that organization is in the best position to make the determination of the impact on stability and B) that organization is responsible (via TPL standards) for ensuring the stability of the grid and connected generating units. (4) In lieu of the blanket 5% exemption, the following is proposed. (a) Delete â€œâ€¦ and with an average Capacity Factor of greater than 5% over the last three calendar yearsâ€ in all places in 4.1.1.1, 4.1.1.2 and 4.1.1.3 (b)Add new Applicabilty 4.1.1.4 stating â€œGenerating facilities with capacity factors less than 5% over the last three calendar years may be exempted with written concurrence from the applicable Transmission Planning Authority. The written concurrence provided by the Transmission Planning Authority shall include the basis for any such exemptions.â€ (5) alternative to (b) could be the reponse to Q9 below.
Yes
(1) We believe the MVA thresholds are appropriate and pick up the vast majority of interconnection (MVA). However, the MVA values MUST be consistent with the MVA thresholds in other stanadrds, such as MOD-10 to 12. and in proposed TPL-001 standards. (2) Supporting data (circa 2003) can be found from the link below which provides a spread sheet titled â€œExisting Generating Units in the United States by State, Company and Plant, 2003.â€ http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/gu_tabs.html The spreadsheet can be sorted and summed to get an estimate of the percentage generation that would be included. A preliminary look suggests that 80% or more would be included.
No
However, add 4.1.1.5 stating â€œGenerating facilities that do not meet the applicability requirements 4.1.1.1 - .3 may be included when their performance is found to create or contribute to reduced reliability of the BES when requested by the applicable Transmission Planner. The written request provided by the Transmission Planner shall include the technical basis for any such inclusion (e.g. must run for reliability, voltage, or stability needs).â€
No, the phase in period for unit excitation system verification should be (please specify below)
(1) The term "verification" should be defined. Defining "verification" would give Generator Operators/Generator Owners a clearer understanding of what data should be verified in the model. (2) The first time period should be 3 years (10%). It is anticipated that the first units will take significantly longer than subsequent testing. Although this factor is already being considered

in proposed time periods, there will probably be a significant shortage of testing services at the beginning of the testing window. (3) The last period for 100% of appliable units should be 12 years to match with 12 years of outage cycle.
None
None
(1) Requirement 1 states that testing should occur "for new or existing units within 180 days of commerical operation". We believe the testing for the new units should be done before commerical operation. (2) In Requirement R2, the Transmission Planner would not necessarily have any idea which model would best fit the installed equipment. The only workable way to comply with this requirement is for the Transmission Planner to give the Generator Operator the data sheets for the entire library of available exciter models. The Generator Operator would then need to determine which of these models would provide the best fit for the excitation system equipment to be modeled. We believe that this requirement should recognize that deriving "acceptable" model for a specific excitation system is a cooperative effort between manufacturer, GO/GOP, and TP. (3) While wind generators would generally fall below the unit size thresholds as specified in Requirement 4.1.1, it would be very helpful in conducting dynamic simulations involving wind generators if their dynamic representations would be fit into one of the standard library models. (4) There are several 90 day periods mentioned in the Requirements. It might be helpful to be more specific as to which 90 day interval is meant. For example, Requirement R8 should read something like "â€¦within 90 days of completion of the excitation system model verification as specified in Rx." (5) This comment is in reference to MOD-026-1, R.12. We believe that Digital Control Systems do not effect excitation systems models. Therefore we suggest removing requirements associated with Digital Control Systems.
Individual
Armin Klusman
CenterPoint Energy
Yes
CenterPoint Energy concurs with the SDT that this is a reasonable approach.
Yes
CenterPoint Energy concurs periodic verfication every ten years is appropriate.
Yes
Yes
Yes
Individual
Mark Thompson
AESO
No
The AESO agrees with the SRC ISO/RTO comments.
No
The AESO agrees with the SRC ISO/RTO comments. We would also like to add: WECC requirements state every 5 years. 5 years seems more resonable than 10 years to ensure that the generating unit is still performing as intially sepceified and there has been no no component degradation causing the settings to drift.
No
The AESO believes that using a single unitâ€™s actual excitation system verification to be a proxy for multiple units will not pick up errors in settings, component failures, alterations to units, etc. Each unit should be tested individually.
Yes

The AESO agrees with the SRC ISO/RTO comments.
Yes
The exciter is only one component of the generator, testing all components (generator, exciter, PSS and governor/prime mover) is imperative so a complete picture of how the unit will react within the electrical system can be modeled. For the same reason units such as wind facilities and other types of generation that do not have an exciter must be modeled and verified.
No
The AESO agrees with the SRC ISO/RTO comments.
Yes
The AESO agrees with the SRC ISO/RTO.
No (disagree with approach)
The AESO agrees with the SRC ISO/RTO comments.
No, instead use the approach below:
Section 4.1.1.2 directly references the Western Interconnection but then uses equipment sizes as a base that far exceeds the ones used by WECC in the Generating Unit Model Validation Policy. 75 MVA units vs 10MVA by WECC 20 MVA units in a 150 MVA facility vs. 20 MVA facility by WECC 100 kV interconnection vs. 60 kV by WECC Perhaps the standard can reference the WECC guidelines.
The AESO agrees with the SRC ISO/RTO comments.
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
The AESO agrees with the SRC ISO/RTO comments.
The ones we are aware of have been noted in the responses previous questions.
The AESO agrees with the SRC ISO/RTO comments. We would also like to empahsize the importance of complete unit testing as noted in our response to Question 4.
Individual
Greg Rowland
Duke Energy
No
Based on Responsibilities in the Functional Model, responsibility for determining maintenance and verification activities is clearly assigned to the Generator Owner. It should also be noted that in some cases the GO may be able to obtain additional expertise from their TP, RTO, or Region, which adds other resource options.
No
It would seem that the need to revalidate is driven by technical issues (analog controls drift, digital doesn't). There is an EPRI guide (1004556) that specifies a 5 year frequency for analog AVR calibrations. The SDT should discuss different periods based upon different control technologies (e.g. digital versus analog). In addition to R12, some communication between the Generation Operator and the Transmission Operator within the 10 year period would be reassuring that nothing has changed.
Yes
If it could be verified that the Gains and TCs are exactly the same, but just reading dial settings on analog controls might not suffice. For digital, the gains are the number programmed in, so the proxy approach is more reasonable. Also, recommend changing MVA rating to 350 MVA so that combined cycle steam units are included.
Yes
Supplying the data itself is appropriate. Industry experience has shown that simply assuring the generator data in the model is the right data for the installed equipment is adequate for assuring the validity of the Generator Parameters, additional testing is not typically needed and any inappropriate data would show up in voltage bump test comparisons needed for AVR models validations. Also, R4.4, should say The GO shall provide the Compensation Function used on the unit (Droop, Reactive Line Drop or Resistive Line Drop) and the amount of compensation provided (% of generator voltage at rated MVA).
Yes
Per the title, this is a standard applicable to the verification of excitation system models and the industry understands this to be different than the generator parameters. Requiring testing to specifically validate that generator data might require more than a bump test, which is currently thought to be adequate to address the issues currently in this standard. The generator reactances and time constants should not need verification as long as there is valid manufacturer supplied data and the generator has not been modified (rotor replacement, etc.) or condition has not degraded, such as the unit has been identified to have shorted rotor turns which would be

expected to impact saturation curves and several of the reactance modeled. Additional testing might be appropriate when it is identified that a unit is operating with shorted turns, or if changes are made if a bump test cannot revalidate what is needed (such as a rotor replacement - do you need to verify saturation curves? or when you remove a rotating exciter, do you need a load rejection test?). NERC should consider establishing and documenting requirements for when model data validation should be re-verified and minimum tests needed for partial unit upgrades â€“ (e.g. what testing is required for a rotor replacement?). Thus, it would seem a supplementary SAR to include generator parameter validation is needed. NERC should also consider developing a guide that provides input on these issues, especially if the responsibility is assigned to a GO/GOP without the technical background in models and validation. SERC developed a guide on this subject that could be leveraged for a NERC guide.
Yes
We agree the standard should not set criteria for evaluating the match, but industry guidance on acceptable criteria would be helpful.
Yes
We agree, but industry guidance on acceptable criteria would be helpful.
No (disagree with approach)
Regarding Section 4 Applicability, drop the reference to Capacity Factor of 5% over the past 3 years. This makes no sense, because for a variety of reasons the unitâ€™s capacity factor in the very next year may be significantly higher, and having an accurate assessment of the unitâ€™s performance would be important. The units with low capacity factor would likely be on line during a peak load period when the system is most stressed and stability issues are most likely. Also, these units could be relevant to sensitivity studies. The larger units should have a model. Additionally, MMWG requires models for all units whether they are on or off in the case. Each one must have a model if the modeling criteria is satisfied. If the unit is a reasonable size and connected to the BES like others, we don't see how you can exclude testing.
Yes
We agree with the approach, but would also caution the team to consider the future composition of the Interconnection MVA. Possibly the team already considered newer types of generation and the benefit of a verified model rather than just â€˜estimated or typical manufacturerâ€™s dynamics dataâ€™ (MOD-013). The team should consider clarifying the relationship between the terms in MOD-013 and MOD-026. Is â€˜unit-specific dynamics dataâ€™ equivalent to a â€˜verified modelâ€™? Even in the case of a sister unit? If a unit does not meet the applicability for MOD-026, would they then follow MOD-013 to determine the applicable model to provide?
Yes
Add a similar requirement to R11 that allows the TO or RC to add a generator that does not meet the applicability criteria when their performance is found to create or contribute to reduced reliability. No one can foresee all future system configurations and operating conditions. This type of requirement is fundamental to analyzing and resolving issues. Additional Comment on R11 and R12. When system or plant events occur impacting transient voltage response, the GOP should evaluate actual unit/plant performance against expected performance. This is especially important when taking credit for sister units to avoid testing of similar units at the same site. With the long time between verification testing (10 years) and even longer time frame when allowing for claiming sister units, it is important to assess actual versus predicted performance. It is not sufficient to have only the TO or RC identify potential issues because they would normally only recognize issues that negatively impact the entire system and only for the specific event. Individual generating stations may have not behaved as modeled due to protection/control problems but the overall system met requirements.
Yes, agree with proposed phase in period for unit excitation system verification
We wanted to also check "YES" on allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date, but this electronic form wouldn't allow us to do that.
None
None
Section 4.1 Should the standard be revised to include small units that are part of an aggregate 200 MW facility? For example : wind farms with many 1.5 MW turbines Recommend changing R5.1) to read â€œThe model initializes properly and a no-disturbance simulation contains no transients.â€ The second bullet of R7 allows an unusable model to not be corrected. Unless the point is that the unit would be out of compliance, this seems to negate requiring verification. Recommend the team to consider that all units that meet the applicability have usable models. For R12, rather than only listing the high level components, we recommend the team also note that other generator components such as a new excitation system power transformer (not a like-for-like changeout) can have an impact on aspects of the model.
Group
FirstEnergy

Sam Ciccone
FirstEnergy Corp.
Yes
Although we ultimately agree, we have the following comments: 1. The Generator Operator should be responsible to verify the dynamic data is accurate for the Generator, Turbine and Excitation system. The ultimate responsibility for the usability and accuracy of the dynamic models and how they perform in relation to the overall system model is the responsibility of the Transmission Planner. 2. Genertor operators in a centrally located dispatch office would not have direct access to the equipment. They can only arrange an actual verification test. Details of the units response to a disturbance would need to be gleaned from the Generator Owner's data. It is not appropriate to burden one entity with a potential compliance violation when another entity controls the data. Relying on agreement coordination between the two entities may not be sufficient to ensure the entity with responsibility to comply is able to comply with an uncooperative entity with data control.
No
10 years for digital excitation systems and 5 years for non-digital excitation systems.
No
1. While we agree with this approach, we do not agree it should be limited to 250 MVA units. It should allow it for any identical units of any size. Also, the requirement could be written more clearly by revising it to make it clear that verification is for similar units only and not all units owned. Based on these comments, we suggest re-wording R1 (2) to state: "For an existing unit, once in a ten calendar year period. If multiple units have identical applicable components and settings and are sited at the same physical location, verification of one unit is sufficient for all of these units. Verification shall be performed on a different unit each ten calendar year cycle." 2. This is a lot like the "Sister Unit" concept developed in the recent RFC generator verification standards. It may be helpful if this term was defined and described in more detail in the standard to allow for ease of compliance verification.
Yes
The question above has a typographical error. We assume the team means "Generator Operator".
No
Yes
1. For many GOP's, a testing contractor with experience in model fitting and selection will need be hired to do the verification. 2. The team may want to add an additional requirement for the Transmission Planner to review and confirm acceptability of the Generator Operator's excitation system model verification documentation within 90 days of submittal. This would preceed the R10 requirement.
Yes
While we agree with the approach of staying away from being too prescriptive, it may add guidance if the term "verify" (i.e. in R1) was clarified. We ask the team to consider adding "such as operational tracking or testing" after verify.
Yes agree with approach and the 5% capacity factor
No, instead use the approach below:
We feel that 80% of the Interconnection MVA is not high enough. The issue might be not including many of the CC/CT units that have a low capacity factor (above 5%). The team may want to consider 90% or further validate the 80% value.
No
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
1. In R1.4 it should be clear that the unit is achieving the 5% capacity factor for the first time over the last three calendar years. 2. R9 states that the Generator Operator shall make documentation demonstrating the excitation system model's response is appropriate available for inspection and technical review 'to' the RC, TOP, and PC. The term "make available" is vague and should be revised to provide more specifics as to how this information is to be made available for inspection and technical review 'by' the RC, TOP, and PC. 3. The term "Capacity Factor" is not NERC defined and is shown as capitalized in the standard. We suggest the team develop either a

standard-specific or NERC Glossary definition. The following is a suggestion: "Capacity Factor (expressed as a percent) - The net actual energy generation (MW-hours) divided by the product of the period (hours) and the net maximum nameplate rating (MW)." 4. Sec. 4 Applicability - We do not agree with the criteria proposed for the Eastern Interconnection and believe it may leave out some important or critical units. Also, it may be better to just have one criteria throughout the interconnections. We recommend the SDT consider using the NERC Registry Criteria for all units based on plant aggregate of 75 MVA or greater and unit size of 20 MVA or greater. 5. Per Question 10 above, why wouldn't the Regional Entity procedures or guidelines be allowable for compliance after the first 5 years? [Note: It is assumed that the SDT intended to say "first" 5 years, not "last" five years in the description after Box 3 of that question]
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
No
The Generator Operator does not have direct access to the equipment. The Generator Owner is the correct Functional Model entity that has direct access to the equipment and the authority to perform testing of equipment. All responsibilities assigned to the Generator Operator in the proposed standard should be reassigned to the Generator Owner.
Yes
ten-year interval is acceptable given the conditions in Requirement R12.
No
Units testing has in the past identified different responses from identical units with common settings. All units with identical design and settings should be tested unless records of actual system events demonstrate that all of the units respond the same.
Yes
The entity specified in Question 4 does not agree with the entity specified in Requirement R4. As stated in our response to Question 1, we believe the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity to be the GO.
No
Expanding the scope to include verification of generator data will not provide a significant improvement in the overall modeling of excitation systems. However, these data should be provided as part of an existing Standards or from another Standards if not already existing.
No
As stated in our response to Question 1, we believe that the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.
Yes
Reliability Standards should focus on what is required and not how to meeet the requirement. Further, it would be impractical to specify verification details universally applicable to all situations. The peer review process provides appropriate safeguards to ensure that appropriate methods are used for verification. As an alternative, a technical white paper could be developped for reference.
Yes agree with approach and the 5% capacity factor
We agree with this approach to exclude units with low capacity factors provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. Cases exist where large generating units with low capacity factors are operated only during the most stressed operating conditions. In such cases accurate modeling of these units may be critical to reliable operation of the bulk electric system.
Yes
We agree with the general approach to base the number and size of applicable generating units on the objective of validating models for 80 percent of the installed capacity on an Interconnection provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. In the event the Planning Coordinator or Transmission Planner is not permitted to identify additional units, the objective should be changed to validate models for a greater percentage of the installed capacity. We do not have data to verify whether the unit size thresholds specified in Requirement R4.1.1 correspond to 80 percent of the installed capacity on an interconnection, and respectfully suggest that it is the responsibility of the SDT to provide such verification.
Yes
The Planning Coordinator or Transmission Planner should be permitted to identify additional units

for applicability of the Standard based on the results of generator interconnection studies or other studies that demonstrate the criticality of correct settings on system reliability, e.g. studies demonstrating sensitivity of a stability based System Operating Limit to correct equipment settings and functionality.
No, the phase in period for unit excitation system verification should be (please specify below)
The proposed impmentation plan is too long. We recommend a five-year implementation with a requirement that units representing 20 percent of installed capacity be tested each year. We are concerned that an eleven-year implementation plan does not adequeately promote system reliability, and that having only three milestones will place a burden on system operators to schedule testing because Genator Owners may wait until years two, six, and eleven to schedule testing instead of spreading the tests out over the implementation period. Credit could be allowed for verification of excitation systems within the last five years of the Standards approval date.
Yes, we have a modification to propose to the Applicability section which list different value for diffferent Region or Interconnection. We propose that the two paragraphs in Applicability 4.1.1.1 be modified to: «Each unit (including synchronous condensers) â‰¥ 50 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.» «Each unit (including synchronous condensers) â‰¥ 20 MVA within a plant â‰¥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.»
Group
Pepco Holdings, Inc (PHI) - Affiliates
Richard Kafka
Pepco Holdings, Inc (PHI)
No
PHI believes that the Generator Owner should be responsible, but recognizes that the GO and GOP may be the same in most cases.
Yes
No
A GOP (or GO) may have sister units (identical units) at diffrent locations. This should not be restricted to one location.
Yes
No
Yes
Yes
Yes agree with the approach. But use another capacity factor (include supporting data):
PHI does not see a substantial difference in reliablity if the capacity factor is increased to 10%
Yes
No
Yes, agree with proposed phase in period for unit excitation system verification
Individual
Alice Murdock
Xcel Energy
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes agree with approach and the 5% capacity factor
Yes
Yes
Yes, we agree, however the SDT needs to give consideration to whether the Generator Owner has any rights to dispute such designation from its TP or PC.
Yes, agree with proposed phase in period for unit excitation system verification
Capacity Factor needs to be defined.
Individual
Dan Rochester
Independent Electricity System Operator
No
This responsibility rests with the Generator Owner. As indicated in the Background Information Section, Generator Owners may be responsible for providing accurate generator data including the excitation data for system modeling. Although it does not operate the generator, verification testing does not need to be performed under operating conditions only. The input/output measurements of the excitation system could suffice to verify the excitation system model, which may be performed during commissioning testing or under other non-production conditions. If the generator must be run by the Generator Operator to enable testing, the Generator Owner can make such an arrangement with the Generator Operator under an agreement, as the Background Information so suggests.
No
We believe a 10 year re-verification period is adequate for those exciters whose settings do not tend to drift over time. However, a shorter period, say 5 years, should apply to the analog or rotating type of exciters.
Yes
We agree with the proxy unit approach only if these units' excitation systems show identical performance based on the results of a limited number of tests. On the other hand, we do not agree with the 10-year cycle. Accurate excitation system data and verification that it performs as designed are critical to accurate modeling and simulation to support a wide range of reliability activities, including the determination of SOLs and IROLs. The 10 year recycle period is too long that risks changes to excitation system characteristics undetected. We suggests this period be shortened to 5 years.
Yes
We agree with the approach of requiring the Generator Owner to supply the data listed. We also suggest that since this data is required within 90 calendar days of completion of the excitation system model verification - the same condition for providing documentation demonstrating that the excitation system modelâ€™s response matches the recorded response for a voltage excursion at the generator as stipulated in R8 - we suggest R8 be combined with R4. Note that "Generator Owner" instead of "Generator Operator" is used in this question. While we view this as a typo, as indicated in our comment under Q1 we think it is appropriate that the Generator Owners be held responsible for the majority of the requirements in this standard.
Yes
We think that at a minimum, the generator's basic characteristics such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), voltage regulators, turbine-governor systems, etc. as stipulated in MOD-013 that

support modeling for dynamic simulations should be verified. A good excitation system model without a valid generator model will not provide the assurance that the simulation results are valid, which may hurt reliability.
No
We have difficulty with the concept since the GOP's determination of a "match" can be subjective and subsequent peer review is time consuming and unnecessary if some matching criteria is developed up front. While we are not in a position to suggest what that criteria should be, we tend to think that a certain percentage of deviation in some output parameters may serve to provide this measure. Also, as indicated under Q4, we suggest R8 be combined with R4. It may be a moot point if some criteria are developed but if not, there are inconsistencies among R4, R8, R9 and R10 on the recipients of the documentation that the Generator Operator must provide and the feedback to be received. We suggest the SDT review the list of recipients, and if peer review is still required then the recipients/commenters should include Transmission Planners, Planning Coordinators, Transmission Operators and Reliability Coordinators since they all are users of the data and model.
Yes
The SAR could be expanded by making it more clear that it applied not only to the excitation systems on conventional synchronous generation units but also to the equipment that performs this role on non-conventional facilities such as wind-farm voltage management systems.
No (disagree with approach)
a. The Term Capacity Factor is capitalized but this term is not defined. Suggest to use lower case, or define it. b. Capacity factor reflects a generating unit's real power generation frequency and duration, but does not provide the assurance that when the generator is on line, it's excitation system has been modeled accurately such that its expected performance matches simulation results. There are generating units that are often on line but do not generate at high capacity since they provide ancillary services including operating reserve and hence tend to have a low capacity factor. There are also sizable "mothballed" units or the entire plant of multiple sizable units that, due to various reasons, were put off line for a long period but return to service when the need for capacity so dictates. Not having their data verified based on a low capacity factor and on the assumption that they constitute a small portion of the interconnection MVA may leave room for unreliability. Further, low capacity factor is a historical value which may not be a good indicator of the future. If and when these low-capacity generators are put to high capacity usage, and particularly when the system is being stressed, the non-verified excitation systems can give rise to unpredictable system performance. Moreover, having to track a unit's capacity factor for the past 5 years to determine the need for verification is an unnecessary administrative burden.
Yes
We do not have any technically sound alternatives to suggest.
Yes
In some areas on the interconnection, such as those that are sparsely populated, performance of generating units at less than 100 MVA might be critical to reliability. The criteria to allow the TP and PC to identify these units could include: a. A 5% or 10% deviation of any or several of the excitation system's parameters/settings could make an otherwise stable simulation to be unstable; b. Use of generic models for the excitation system or generator would make an otherwise stable simulation to be unstable. c. Other changes or incorrect assumptions for the excitation system or generator would make an otherwise stable simulation to be unstable.
No, the phase in period for unit excitation system verification should be (please specify below)
10 years is too long a period to phase in full compliance with this standard. We recommend this be shortened to no more than 5 years so that the continent can have a fully verified set of excitation system data by that time to support modeling and simulation. This has been long overdue, and allowing the 10-year phase in period prolongs achieving the desriable reliability objectives. We also suggest the SDT to consider shortening the re-verificaiton cycle to 5 years.
Variances are already provided in the Applicability Section (for the 3 Interconnections).
None
We offer the following comments: a. A number of points/bullets in several requirements need to be performed to meet the intent of the main requirements, even though some of them are mutually exclusive (i.e. either/or). As such, they should be labeled subrequirements. These include: - R1: Points number 1 and 2 - R4: Points number 1 to 5 - R11: All bullets - R10: Both bullets - R12: The last 2 bullets b. R5: The condition that "if the excitation system model is useable" needs further elaboration. Evidence showing either Conditions (1) or (2) may suggest that either the model incorrectly reflects the excitation system or the excitation system itself, despite being modeled correctly, gives rise to the observed condition. The word "useable" thus needs to be expanded to more properly indicate whether the data is not useable or the excitation system is not useable. c. R6: The above comment on R5 also applies to R6.

Group
Entergy Fossil Operations
Stan Jaskot
Entergy Fossil Operations
No
Gnerator Owners are responsible for the maintenance of the units. This testing is not an on-line normal test. It is more of a maintenance/engineering task that would use 3rd parties to help perform. This would also require special budgeting and running a unit with off normal conditions which an owner would have to approve and sanction. Generator Owners are responsible for other Modeling standards, so wht would they not be responsible here. This is also providing data that is of no use to the Generator Owner or Operator and they will not have any expertise with this work. Only the Transmission Planner needs this data and should understand it. In that aspect, they should take some responsibility for it.
No
I am OK with 10 years for analog systems. Newer digital systems should not change over time, so they should be tested upon commissioning and that should be adequate for the life of the unit.
Yes
I agree with this except for the less than or equal to 250 MVA. It should apply to all units meeting the sister unit criteria regardless of MVA. If you want a limit, then make it something higher like 80% of the single largest generator in the system.
No
I may agree if it is reasonable and list exactly what data can be requested by the TP. Remember, the GO is dependent on contractors for doing this, it costs them money, and is of no benefit to the GO, so the listing need to be specific so it can be listed in the job scope of the work and reasonable.
No
No
This should be the Transmission planner's job. The GO or GOP does not use this data or the software or the expertise and may not be aware of disturbances on the system. The TP should compare this data and furnish it to the GO if there is an issue.
No
I do agree with not making the standard too large, but somewhere the GVSDT needs to provide this detailed data or training to the GO/GOP. You are requiring them to provide things that they do not have expertise in and this will lead to problems with getting this done correctly and for a reasonable price. I'm sure the contractors that do with work see a big opportunity to make money on this.
Yes agree with approach and the 5% capacity factor
Yes
No
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date
I vote yes on both of the questions.
In Requirement R5 in the event that a model is determined to be unusable and is returned to the Generator Owner for further action the transmission operator should be required to also provide the steps he has taken to exercise due diligence in the integration of the exciter system model into the over all model. This should take the form of review of data inserted against data provided, model name reviewed against model provided, etc. The transmission operator should also provide the Generator operator witih text copy of the actual exciter and generator portion of the overall model.
Individual
Tony Kroskey
Brazos Electric Power Cooperative
No
Even though a Generator Operator could possible supply and verify the information, it should be the Generator Owner who owns equipment design information that is responsible for it and be

directly responsible for compliance with the requirements.
Yes
Yes
Yes
No
The Generator Owner should be responsible.
Yes
Yes agree with approach and the 5% capacity factor
No
Group
IRC Standards Review Committee
Ben Li
IESO
No
This responsibility rests with the Generator Owner. As indicated in the Background Information Section, Generator Owners may be responsible for providing accurate generator data including the excitation data for system modeling. Although it does not operate the generator, verification does not need to be performed under operating conditions only. The input/output measurements of the excitation system could suffice to verify the excitation system model, which may be performed during commissioning testing or under other non-production conditions. If the generator must be run by the Generator Operator to enable testing, the Generator Owner can make such an arrangement with the Generator under an agreement, as the Background Information so suggests. Further, we believe both the Transmission Planner and the Planning Coordinator are primary users of the model. We suggest that the Planning Coordinators be added to the Applicability Section, and at places where Transmission Planners are assigned a responsibility.
No
While a 10 year re-verification period may be adequate for those exciters whose settings do not tend to drift over time, a shorter period, say 5 years, should apply in general since there are analog and rotating type of exciters whose settings tend to drift from time to time.
Yes
We agree with the proxy unit approach.
Yes
We agree with the approach of requiring the Generator Owner to supply the data listed. We also suggest that since this data is required 90 calendar days of completion of the excitation system model verification - the same condition for providing documentation demonstrating that the excitation system modelâ€™s response matches the recorded response for a voltage excursion at the generator as stipulated in R8, we suggest R8 be combined with R4. Note that "Generator Owner" instead of "Generator Operator" is used in this question. While we view this as a typo, as indicated in our comment under Q1 we think it is appropriate that the Generator Owners be held responsible for the majority of the requirements in this standard.
No
This standard should focus on the excitation system only. If the industry sees a need for such verification, the requirements could be added to another MOD standard or a separate standard be created through a separate SAR.
No
As the facility owner, the Generator Owners should have the authority to confirm the accuracy of the model, which when supported by documentation, should suffice. A peer review is not

necessary, and if "match" must be quantified, the industry may develop a set of criteria based on historical verification test data, and add this to the standard at a later stage.
Yes
No (disagree with approach)
a. The Term Capacity Factor is capitalized but this term is not defined. Suggest to use lower case, or define it. b. Capacity factor reflects a generating unit's real power generation frequency and duration, but does not provide the assurance that when the generator is on line, it's excitation system has been verified such that its model is accurately represented in simulations. There are also sizable "mothballed" units that, due to various reasons, were put off line for a long period but return to service when the need for capacity so dictates. Not having their data verified based on a low capacity factor and on the assumption that they constitute a small portion of the interconnection MVA may leave room for unreliability. Moreover, having to track a unit's capacity factor for the past 5 years to determine the need for verification is an unnecessary administrative burden.
Yes
We do not have any technically sound alternatives to suggest.
Yes
In some areas on the interconnection, such as those that are sparsely populated, performance of generating units at less than 100 MVA might be critical to reliability.
No, the phase in period for unit excitation system verification should be (please specify below)
We suggest that the usual implementation language be used. Requirement R1 sets the schedule for verification even for the first time based on a 10-year cycle (we suggest to be shortened to 5 years, especially for the analog and rotating type exciters). We agree with allowing credits for verification of excitation systems within the last 5 years of Standard's approval date.
None
None
We offer the following comments: a. The proposed standard lacks clarity needed for implementation as a mandatory standard. Specifically, there are different views in the industry as to what exactly is a model data sheet. Is it the block diagram of the excitation system's control system and parameters, or is it the simulation software's model sheet such as, for example, a vendor's data sheet for a specific type of exciters which it is capable of modeling in its simulation software, say, IEEEST, EXST1, or whatever name it may be, etc. We suggest clearer language be used to more specifically describe what a model data sheet means. Also, verification is subject to interpretation: is it a comparison of the expected input/output response of the excitation system versus actual response, or the expected performance of the generators when a computer simulation is conducted? b. A number of points/bullets in several requirements need to be performed to meet the intent of the main requirements, even though some of them are mutually exclusive (i.e. either/or). As such, they should be labeled sub-requirements. These include: - R1: Points number 1 and 2 - R4: Points number 1 to 5 - R11: All bullets - R10: Both bullets - R12: The last 2 bullets c. R5: The condition that "if the excitation system model is usable" needs further elaboration. Evidence showing either Conditions (1) or (2) may suggest that either the model incorrectly reflects the excitation system or the excitation system itself, despite being modeled correctly, gives rise to the observed condition. The word "usable" thus needs to be expanded to more properly indicate whether the data is not usable or the excitation system is no useable. d. R6: The above comment on R5 also applies to R6.
Individual
Jason Shaver
American Transmission Company
Yes
No
The 10 year period is too long and should be changed to 5 years in order to ensure greater model accuracy.
Yes
It provides confirmation of whether the data being used to model the generator and the generator data used in the verification test are the same.
Yes
Yes

No
Standard testing procedures should be provided as a minimum with the caveate "that the testing procedures include but are not limited to these procedures" to cover future technologies. An example would be a step response test for the exciter; swept frequecy (0.1 t0 10 Hz) response test for a PSS.
Yes agree with approach and the 5% capacity factor
No, instead use the approach below:
The threshold should be based on NERC registration criteria for Generator Owners/Operators. See Appendix 5 Organization Registration and Certification Manual. (Version 3.3) This criteria should apply across NERC. Item 2 in Requirement 1 should be set to the same level used by NERC's registration criteria for plants.
No
This standards should apply to all registered GO's and GOP's. A requirement as suggested puts the TP or PA in the position of telling NERC who should be registered. This responsibility that clearly falls to NERC and the Regional Entities and should not be expanded to any registered entity.
No, the phase in period for unit excitation system verification should be (please specify below)
20% per year for the next 5 yesrs.
ATC disagrees with portions of Requirement 2 which stipulates that the TP shall provide the excitation system model block diagram (block diagram) structure and data requirements. Many manufactures currently make their block diagrams and data requirements available to the GO/GOP. In addition, IEEE Standard Definitions for Excitation System for Synchronous Machines allows a GO/GOP to identify the type of exciter and/or PSS installed on their units along with the corresponding block diagrams and data requirements. Recommend that the words following "â€¦ dynamic simulation software." be deleted.
Individual
Jay Seitz
US Bureau of Reclamation
No
We believe the Generator Owner should be responsible for model verification. The existing NERC Standard, MOD-012-0 requires the Generator Owner to provide dynamic system modeling and simulation data to the RRO. In addition, MOD-013-0, RRO Dynamics Data Requirements and Reporting Procedures (not FERC approved), requires the RRO to coordinate with the Generator Owner to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze dynamic behavior. As such we believe this standard should be consistent and apply to Generator Owners. In addition, the NERC Reliability Functional Model - Version 4 describes the Generator Owner relationships with other entities including "Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner."
No
We believe the 10 year period is too long. It is hard to make the case for reliability-based need for this standard when 10 years are allowed to complete the modeling. Suggest changing the initial implementation period to 5 years which is the implementation period provided in the WECC regional policy. Ten years may then be appropriate for re-validation.
Yes
We agree the Generator Owner should provide the data and also be resposible for performing the model validation/verification.
Yes
Yes, we believe other accurrate dynamic models (e.g. generator model, governor model) are needed for valid computer simulations and should be required. Existing standards, MOD-012-0 Dynamics Data for Transmission System Modeling and Simulation and MOD-013-0, RRO Dynamics Data Requirements and Reporting Procedures (not FERC approved) already require each reliability region to determine comprehensive dynamics data requirements and Generator Owners to provide such modeling data. If these standards are being performed it is questionable what additional reliability concern is served by draft PRC-026-1.
No
Again we think the Generator Owner should be the responsible entity. This standard applies to only two entities, the Generator entity and the Transmission Planner; however actions by other

entities , Reliability Coordinator and Transmission Operator, are required to accomplish the goals of the standard. The exact requirements of these entities should be described in the Standard.
Yes
No (disagree with approach)
Capacity Factor (capitalized) is not defined in the standard nor is it defined in the NERC Glossary; we think we know what it means but if the term is used in the standard it should be defined. However we believe Capacity Factor, should not be used to exempt generators. Those times when generators of low Capacity Factor are in operation will most likely be those times when the power system is most stressed and the performance of the machines should be modeled in system studies.
No, instead use the approach below:
We believe the NERC Compliance Registry Criteria should be used as the threshold.
Yes
If a unit or facility is critical to reliability and the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator can present convincing evidence, the plant should be included. The criteria to use should be developed by the above entities.
No, the phase in period for unit excitation system verification should be (please specify below)
We recommend a 5-year phase in period.
WECC has developed a comprehensive regional machine testing and model validation policy that includes dynamic models for all the major generation components and the applicability thresholds are much more strict than those proposed in the draft MOD-026-1.
We see a blurring of the requirements between Standards MOD-012-0-Dynamics Data for Transmission System Modeling and Simulation; MOD-013-0- RRO Dynamics Data Requirements and Reporting Procedures; and the draft of MOD-026-1 - Verification of Models and Data for Generator Excitation System Functions. If entities are in compliance with MOD-012-0 and MOD-013 we see no additional enhancement to reliability by the addition of this draft standard.
Individual
Daniel J. Hansen
Reliant Energy
No
Generator Operators should not have the sole responsibility alone. With the Generator Operators typically not having the in-house expertise for the model verification, they must not only pay the cost of hiring consultants, but will also carry the burden of significant costs for low capacity factor units when trying to schedule the consultants for unpredicable run times. WECC unit verification testing has resulted in very expensive startup costs for low capacity factor units just to perform a test. There is no cost recovery method for running a unit out of the money to perform this testing.
Yes
Yes
Proxy unit ratings should go up to 500 MVA.
Yes
No
No
Peer review works well when performed by reasonable professional with the right motives. The only disagreement is that the Transmission Planner can arbitrarily reject the model and data without assuming any responsibility for the corrections or the cost.
Yes
Yes agree with the approach. But use another capacity factor (include supporting data):
Capacity factor should be raised to 15%.
No, instead use the approach below:
Each unit (including synchronous condensers) â‰¥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 15% over the last three calendar years. Each unit (including synchronous condensers) â‰¥ 50 MVA within

a plant â‰¥ 250 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 15%
No
Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standardâ€™s approval date

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Draft Standard MOD-026-1 for the Generator Verification Standard Drafting Team — Project 2007-09

The Generator Verification Standard Drafting Team (SDT) thanks all responders submitting comments on the proposed revision to the MOD-026-1 — Verification of Models and Data for Generator Excitation System Functions standard. This standard was posted for a 45-day public comment period from February 17, 2009 through April 2, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 45 sets of comments, including comments from more than 100 different people from over 50 companies representing 8 of the 10 Industry Segments as shown in the Attachment on the following pages.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

In the formation of the first draft of this excitation control system model verification standard, the SDT first considered the functional entity "applicability". The SDT quickly recognized that assigning responsibility to appropriate entities for a continent-wide standard on verifying unit excitation system models would be difficult. The reason is that there are many business model variations regarding excitation model verification in place today. The SDT decided that a generation entity was the appropriate entity to assign ultimate responsibility, and posed this question to industry. The vast majority of respondents did not think the Transmission Planning entity was the correct entity to perform verification. There was a significant portion of industry that thought the Generator Owner should be responsible instead of the Generator Operator. The SDT consulted the Functional Model Working Group (FMWG), who rendered the opinion that the Generator Owner should be responsible for model verification, not the Generator Operator. Based on consultation with the FMWG, and supported by the majority of industry comments, the SDT has changed the applicability from the Generator Operator to the Generator Owner.

The SDT asked the industry several questions regarding applicability and frequency of excitation control system model verification. The industry responded that the proposed ten-year periodicity, the proxy unit concept, exemption for units that have a 5% or less capacity factor, and an applicability on an Interconnection basis corresponding to at least an 80% installed MVA generation capacity are all acceptable. Based on industry comments, the SDT is proposing that the proxy unit cutoff be raised from 250 MVA to 350 MVA (the other criteria remaining unchanged). Also based on industry responses, the SDT is proposing a modified applicability to additionally include a significant MVA percentage of all generation of all technologies, including Variable Energy Resources.

The SDT also asked industry about the role of generator model data, because the excitation control system model is a closed loop system that includes the generator data. Industry stakeholders indicated that the standard needed additional clarity about the exact expectations for generator data, but indicated that expanding the scope of the standard to include verification of generator models was not appropriate.

There was support for the SDT approach of the standard "stating what is required" without "stating how to accomplish what is required". Specifically, the industry agreed that the generation entity (the Generator Owner) should be tasked with determining if the model's predicted response and the actual equipment's recorded response are sufficiently matched, and with the concept of the standard providing minimal specificity regarding the mechanics of performing excitation system verification.

The SDT asked the industry if there was a need to specify a process where additional critical units could be identified for excitation control system model verification. A majority of the industry respondents from all Regions indicated "yes". Additionally, there were some minority concerns that the drafted applicability excluded some units that are covered by the NERC Registry Criteria. In response, the SDT developed a proposed process (details contained in Requirement R5) that requires technical justification but which allows the Planning Coordinator to identify additional units whose excitation control system performance requires scrutiny by the Generator Owner. In some instances, scrutiny by the Generator Owner could lead to corrected model data that could meet the needs of the Planning Coordinator. But unless the Generator Owner can determine that the existing model structure and data requires a correction and subsequently meets the needs of the Planning Coordinator, the model must be verified. The SDT originally considered letting the Transmission Planner identify critical units along with the Planning Coordinator. However, the SDT realized that Transmission Planners could bring model issues to the attention of their Planning Coordinator so that the Planning Coordinator could make a determination about whether the model issue warranted further review by the Generator Owner.

While stakeholders generally agreed with the proposed implementation plan concepts, they expressed some concerns about sufficient start up time. Thus, the SDT decided to propose extending the time after the standard is approved for the first required set of models to be verified from "2 years following regulatory approval, 10% its applicable units per Interconnection on a MVA basis" to "4 years following regulatory approval, 30% of its applicable units per Interconnection on a MVA basis".

Finally, based in part on industry comments, the layout and the formatting of the standard have been significantly updated. Periodicity has been moved to a separate attachment, as the SDT determined that it is not a stand-alone reliability requirement. The standard no longer attempts to follow an expected chronological sequence, but instead is arranged to include the necessary results-based reliability requirements. The most visible modifications are that the numbers of Requirements have been drastically reduced.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 315-439-1390 or herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. **The SDT recognized that a determination had to be made regarding which entity should be ultimately responsible for model verification. The SDT was of the opinion that the Generator Operator, instead of the Transmission Planner or Generator Owner, was the appropriate entity to be responsible for the model verification. The Generator Operator operates the equipment being verified, and has direct access to the equipment. The Transmission Planner has the simulation software, but does not typically have access to the equipment or have testing capabilities. It is recognized that Generator Operators typically do not have in-house expertise and would have to either hire consultants to perform model verification, or develop in-house expertise including acquiring simulation software.** 12
2. **The SDT recognizes that depending on the technology of the modeled equipment, the periodicity of model verification necessary to ensure accurate models could vary. Also, the team recognizes that the majority of the resulting reliability benefit will occur during the initial verification. The SDT determined that 10 years would be an appropriate period for re-verification in the absence of other activities listed in Requirement R12 that would require an earlier re-verification.** 25
3. **The SDT thought that it would be reasonable to apply a philosophy to allow maximization of limited resources required to perform excitation system model verification. The philosophy allows a single unit's actual excitation system verification to be a proxy for multiple units if the following conditions are met: a) the units have the same MVA rating, b) the units are rated at≤ 250 MVA c) the units have identical applicable components and settings and d) the units are sited at the same physical location. For each recurring 10 year cycle, another unit must actually be verified.** 34
4. **The list of unit specific information in Requirement R4 to be provided to the Transmission Planner from the Generator Owner includes generator data used in the excitation system verification process. The reason is that the tests, ambient or staged, which are used to verify the excitation system model, are part of a closed loop system that includes the generator. However, the SDT stopped short of requiring verification of either all generator data, or a portion of the generator data which is most applicable to excitation system testing (Transient Open Circuit Time Constant, and for PSS model verification, rotational inertia). The SDT feels that it cannot develop draft Requirements for the verification of generator data without submitting a supplementary SAR to the NERC Standards Committee.** 43
5. **MOD-026 Requirement R8 requires the Generator Operator to provide documentation demonstrating that the provided model's response matches the recorded response. It does not specify criteria for evaluating the match. Requirement R8 assigns the task of evaluating the match to the Generator Operator. A peer review process for this documentation, detailed in Requirement R10, gives other involved parties an avenue to provide input and voice any concerns.** 61
6. **The team purposely provided minimal specificity regarding the mechanics of performing excitation system verification and the development of the documentation showing that the provided model response matches the recorded response. The team felt it was impractical to provide verification details in a mandatory Reliability Standard that needs to be applicable to all of the existing and future technologies.** 70
7. **The SDT believes that this standard should not be applicable to low capacity factor units. The SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and**

MOD-013. These models and data should, with few exceptions, already accurately replicate actual equipment performance. By definition, low capacity factor units are expected to rarely be on-line, and even when they are, they would constitute a small portion of the interconnected MVA. As such, the SDT is of the opinion that verified excitation models for these units would not result in a substantial increase in Bulk Electric System reliability. Do you agree with this approach and the proposed 5% capacity factor? 76

8. **The SDT is of the opinion, based upon sound engineering judgment, that verifying models for excitation systems of generators per the MVA thresholds specified in the Applicability section 4.1.1 will ensure satisfactory performance of Interconnection network simulation models. Do you agree with this approach? If yes, please provide any data in support of the proposed approach including supporting data that the MVA thresholds specified in the Applicability section 4.1.1 correspond to 80% of the Interconnection MVA.** 91

9. **Do you believe the SDT should develop a Requirement to allow the Transmission Planner or the Planning Coordinator to identify additional applicable units beyond those specified in section 4.1.1 due to their criticality to the reliability of the Bulk Elecric System? If yes, please include the criteria that should be used by the Transmission Planner or Planning Coordinator to identify critical units with MVA rating less than listed in section 4.1.1 and any supporting data.** 100

10. **The SDT is proposing an implementation plan that requires certain percentages of applicable units to be verified two, six, and eleven years after the standard is approved. The SDT also thought it would be prudent to allow the verification of excitation systems per Regional Entity procedures and guidelines within 5 years of the approval date to be sufficient for demonstrating compliance with this new Reliability Standard. Do you agree with these approaches?** 108

11. **If you are aware of any regional variances that would be required as a result of this standard, please identify them here.** 118

12. **If you are aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.** 121

13. **If you have any other questions or concerns with the proposed standard that have not been addressed in responding to the questions above, please provide them here.** 123

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Robert W. Cummings	NERC Event Analysis & Information Exchange staff										
2.	Group	Edmundo Toro	Southwest Power Pool Generation Working Group	X	X	X		X	X				

Additional members for 1. (Robert W. Cummings):

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dr. Eric Allen	NERC	NA - Not Applicable	NA

Additional members for 2. (Edmundo Toro):

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mitchell Williams	Western Farmers Electric Cooperative	SPP	1, 3, 5, 6
2.	Mike Sheriff	OG+E Electric Services	SPP	1, 3, 5, 6
3.	Brock Ondayko	American Electric Power	SPP	1, 3, 5, 6
4.	Andrew Lachowsky	Arkansas Electric Cooperative Corporation	SPP	1, 3, 5
5.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
6.	Jessica Collins	Xcel Energy	SPP	1, 3, 5, 6
7.	Bill Valagura	Calpine Energy Services	SPP	5
8.	Jim Fehr	Nebraska Public Power District	MRO	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	9. Blake Mertens	Empire District Electric Company	SPP	1, 3, 5, 6									
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	David Kiguel	Hydro One Networks Inc.	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Company of New York, Inc.	NPCC	1
5.	Bruce Metruck	New York Power Authority	NPCC	6
6.	Mike Schiavone	National Grid	NPCC	1
7.	Robert Pellegrini	The United Illuminating Company	NPCC	1
8.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
9.	Randy MacDonald	New Brunswick System Operator	NPCC	2
10.	Greg Campoli	New York Independent System Operator	NPCC	2
11.	Kathleen Goodman	ISO New England, Inc.	NPCC	2
12.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Rick Foster	SERC Dynamics Review Subcommittee (DRS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Sujit Mandal	Entergy	SERC	1
4.	Venkat Kolluri	Entergy	SERC	1
5.	John O'Connor	Progress Energy Carolinas	SERC	1
6.	Herb Schrayshuen	SERC	SERC	10
7.	Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
8.	Lee Taylor	Southern Company Services, Inc. - Trans	SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

9.	Robbie Bottoms	Tennessee Valley Authority	SERC	9
10.	Tom Cain	Tennessee Valley Authority	SERC	9

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jalal Babik	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kirit Doshi	Electric transmission	SERC	1
2.	Jack Kerr	Electric transmission	SERC	1
3.	Craig Crider	Electric transmission	SERC	1
4.	Angela Park	Electric transmission	SERC	1
5.	Solomon Yirga	Electric transmission	SERC	1
6.	Ronnie Bailey	Electric transmission	SERC	1
7.	Chip Humphrey	Generation	RFC	5
8.	Larry Whanger	Generation	SERC	5
9.	Lou Nunez	Nuclear	MRO	5
10.	Phillip Rott	Generation	SERC	5
11.	Tim Wiseman	Generation	SERC	
12.	Louis Slade	Regulatory	SERC	6
13.	Mike Garton	Regulatory	NPCC	6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Don Brown	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gammon	Kansas City Power & Light	SPP	1, 3, 5, 6
2.	Melinda Mangold	Kansas City Power & Light	SPP	1, 3, 5, 6
3.	Nick McCarty	Kansas City Power & Light	SPP	1, 3, 5, 6
4.	Harold Wyble	Kansas City Power & Light	SPP	1, 3, 5, 6
5.	Jerry Hatfield	Kansas City Power & Light	SPP	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MP	MRO	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Terry Bilke	MISO	MRO	2
4.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Jim Haigh	WAPA	MRO	1, 6
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6
8.	Joseph Knight	GRE	MRO	1, 3, 5, 6
9.	Scott Nickels	RPU	MRO	3, 4, 5, 6
10.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
11.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
12.	Pam Sordet	XCEL	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Dave Folk	FE	RFC	1, 3, 4, 5, 6
3.	Mike Williams	FE	RFC	5
4.	Ed Baznik	FE	RFC	1
5.	Ken Dresner	FE	RFC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Richard Kafka	Pepco Holdings, Inc (PHI) — Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Dougherty	Conectiv Energy Supply, Inc.	RFC	5
2.	Art Wolfe	Conectiv Energy Supply, Inc.	RFC	5
3.	Kara Dundas	Conectiv Energy Supply, Inc.	RFC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Stan Jaskot	Entergy Fossil Operations					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jules Guillot	Entergy Fossil Operations	SERC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Steve Myers	ERCOT	ERCOT	2
3.	James Castle	NYISO	NPCC	2
4.	Matt Goldberg	ISO-NE	NPCC	2
5.	Bill Phillips	MISO	MRO	2
6.	Charles Yeung	SPP	SPP	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Individual	Clinton Jacobs	FEUS	X				X					
13.	Individual	Rick Terrill	Luminant Power					X					
14.	Individual	David Schooley	Exelon Corporation	X				X					
15.	Individual	Scott Etnoyer	Constellation Power Generation & Constellation Nuclear					X					
16.	Individual	Hugh Francis	Southern Company	X		X		X	X				
17.	Individual	Russell A. Noble	Cowlitz County PUD			X							
18.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
19.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					
20.	Individual	Ben Johnson	Wisconsin Public Service					X					
21.	Individual	Ronnie C. Hoeinghaus	City of Garland, Garland Power & Light — GOP Registered Entity	X				X					
22.	Individual	Brendan Kirby	AWEA								X		

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Michael Goggin	American Wind Energy Association								X		
24.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
25.	Individual	Baj Agrawal	Arizona Public Service Co.	X		X		X					
26.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	D. Bryan Guy	Progress Energy, Inc.	X		X		X					
29.	Individual	Greg Mason	Dynegy					X					
30.	Individual	Rick White	Northeast Utilities	X									
31.	Individual	Tom Bradish	Reliant Energy					X	X				
32.	Individual	Patrick Farrell	Southern California Edison	X		X			X				
33.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
34.	Individual	Kathleen Goodman	ISO New England Inc.		X								
35.	Individual	Kirit Shah	Ameren	X		X		X	X				
36.	Individual	Armin Klusman	CenterPoint Energy	X									
37.	Individual	Mark Thompson	AESO		X								
38.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
39.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
41.	Individual	Dan Rochester	Independent Electricity System Operator		X								
42.	Individual	Tony Kroskey	Brazos Electric Power Cooperative	X									
43.	Individual	Jason Shaver	American Transmission Company	X									
44.	Individual	Jay Seitz	US Bureau of Reclamation					X					
45.	Individual	Daniel J. Hansen	Reliant Energy					X					

1. The SDT recognized that a determination had to be made regarding which entity should be ultimately responsible for model verification. The SDT was of the opinion that the Generator Operator, instead of the Transmission Planner or Generator Owner, was the appropriate entity to be responsible for the model verification. The Generator Operator operates the equipment being verified, and has direct access to the equipment. The Transmission Planner has the simulation software, but does not typically have access to the equipment or have testing capabilities. It is recognized that Generator Operators typically do not have in-house expertise and would have to either hire consultants to perform model verification, or develop in-house expertise including acquiring simulation software.

Do you agree that the Generator Operator should be responsible for model verification? If not, please explain.

Summary Consideration: The vast majority of respondents did not think the Transmission Planning entity was the correct entity to perform verification. There was a significant portion of the industry that thought the Generator Owner should be responsible, instead of the Generator Operator. The SDT consulted the Functional Model Working Group (FMWG), who rendered the opinion that the Generator Owner should be responsible for model verification instead of the Generator Operator. Based on consultation with the FMWG, and industry comments, the SDT changed the applicability from the Generator Operator to the Generator Owner.

Organization	Yes or No	Question 1 Comment
NERC Event Analysis & Information Exchange staff	No	Comments: Although verification (not validation) of generator equipment settings and testing should be the responsibility of the GO, validation of generator models response to actual system events should be done by the Reliability Coordinator. This offers independent oversight of the validation. Also, validation to system events should be done for multiple events. This provides better insight to generator excitation and control performance over a wider range of conditions than a single staged test.
Response: Thank you for your comments. The SDT does agree that the Reliability Coordinator has a critical role in the process of model verification. However, it is expected that any concerns raised by the Reliability Coordinator will result in a formal request by the Transmission Planner to the Generator Owner. That is why the SDT drafted Requirement R11 (reference Requirement R3 in the revised standard), which allows the Transmission Planner the ability to ask the generator entity to perform a technical review of its current excitation system model. Any concern by the Reliability Coordinator would only occur after a post-mortem review of an actual system event where the observed response of the excitation system was not as expected and so while the Reliability Coordinator may provide feedback, the Transmission Planner is deemed the responsible entity for initiating and providing feedback for this review process. The SDT agrees that validation of multiple events by the Reliability Coordinator is desirable. It is hoped that the vast majority of the time, for the vast majority of excitation system responses reviewed by the Reliability Coordinator, the excitation system response would be as expected and as such, a technical review of the excitation system model by		

Organization	Yes or No	Question 1 Comment
the generator entity would not be necessary.		
Northeast Power Coordinating Council	No	The Generator Operator does not have direct access to the equipment. The Generator Owner is the correct Functional Model entity that has direct access to the equipment and the authority to perform testing of equipment. All responsibilities assigned to the Generator Operator in the proposed standard should be reassigned to the Generator Owner.
Response: Thank you for your comments. The SDT obtained guidance from the FMWG, and as a result of that guidance, your comments, and other industry comments, the draft standard has been modified to assign responsibilities to the Generator Owner instead of the Generator Operator.		
SERC Dynamics Review Subcommittee (DRS)	No	The Generator Owner is the correct entity for this responsibility. It should be the entity that would be able to obtain the attention of the manufacuturer and have the means to accomplish the validation. The entity should have the financial incentives to perform the function and should be knowledgable about the plant operation. The entitiy that would be the best resource to coordinate the testing should be required to verify the models. In our opinion the functional model specifies the Generator Owner as it requires a generator owner to "verify generating facility performance characteristics". For the foregoing reasons this responsibility should not be assigned to the Transmission Planner.
Response: Thank you for your comments. The SDT agrees that the Transmission Planner is not the appropriate entity to be responsible for model verification. Based on your comment, other comments from industry, and input from the FMWG, the SDT has assigned the Generator Owner as the responsible entity for model verification in the second draft standard posting.		
Dominion	No	In general, there should be collaborations between the Generator Owner, Transmission Planner, Generator Operator, and Transmission Operator to meet the intent of model and data verification. However, the requirements of this standard should apply to the Generator Owner and the Transmission Planner. We have reviewed the NERC Functional Model and believe that the Generation Owner should be responsible for those requirements assigned to the Generator Operator in this draft standard. We are concerned that Generator Owners may have to acquire outside sources or develop in-house skills in order to meet the requirements of this standard. However, we believe that the proposed effective date(s) allows adequate time to address these concerns.
Response: Thank you for your comments. The SDT agrees that collaboration from various entities is required to meet the intent of model and data verification. Based on your comment, other comments from industry, and input from the FMWG, the SDT has assigned the Generator Owner as the responsible entity for model verification in the second draft standard posting.		

Organization	Yes or No	Question 1 Comment
MRO NERC Standards Review Subcommittee	No	To help differentiate the BES model from the unit specific excitation system model. The MRO NSRS suggests a change in R1 to read; "The Generator Operator shall verify their applicable excitation control system model?"
Response: Thank you for your comment. After review of IEEE 421.1, the SDT agrees that the term “excitation control system model” is more appropriate than the term “excitation system model” used in the previous draft of the standard. The reason is that the term “excitation control system model” contains the entire closed loop system including the synchronous machine. The SDT has applied the appropriate wording revision in the second draft of the standard.		
Pepco Holdings, Inc (PHI) - Affiliates	No	PHI believes that the Generator Owner should be responsible, but recognizes that the GO and GOP may be the same in most cases.
Response: Thank you for your comment. Based on comments from the industry, your comment, and input from the FMWG, the SDT has assigned the Generator Owner as the responsible entity for model verification in the second draft standard posting.		
Entergy Fossil Operations	No	Gnerator Owners are responsible for the maintenance of the units. This testing is not an on-line normal test. It is more of a maintenance/engineering task that would use 3rd parties to help perform. This would also require special budgeting and running a unit with off normal conditions which an owner would have to approve and sanction. Generator Owners are responsible for other Modeling standards, so wht would they not be responsible here. This is also providing data that is of no use to the Generator Owner or Operator and they will not have any expertise with this work. Only the Transmission Planner needs this data and should understand it. In that aspect, they should take some responsibility for it.
Response: Thank you for your comments. Based on comments from the industry, your comments, and on guidance from the FMWG, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard. The current modeling standards address submission of models and model data, not verification of models and model data. Generator entities are also responsible for verification of MW and Mvars in the current and future draft versions of MOD-024 and MOD-025. Generator Owners have access to the equipment, along with access to the equipment’s Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today’s functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner.		
IRC Standards Review Committee	No	This responsibility rests with the Generator Owner. As indicated in the Background Information Section, Generator Owners may be responsible for providing accurate generator data including the excitation data for system modeling. Although it does not operate the generator, verification does not need to be performed under operating conditions only. The input/output measurements of the excitation system could suffice to verify the excitation system model, which may be performed during commissioning testing or under other non-production conditions. If the generator must be run by the Generator Operator to enable testing, the Generator Owner can

Organization	Yes or No	Question 1 Comment
		make such an arrangement with the Generator under an agreement, as the Background Information so suggests. Further, we believe both the Transmission Planner and the Planning Coordinator are primary users of the model. We suggest that the Planning Coordinators be added to the Applicability Section, and at places where Transmission Planners are assigned a responsibility.
Response: Thank you for your comments. As suggested, the SDT has assigned model verification responsibility to the Generator Owner in the second draft of the standard. While the Planning Coordinator may be a user of the model, the SDT believes that the Transmission Planner is the appropriate entity to interface with the Generator (Owner/Operator) regarding necessary activities that are required to achieve excitation control system model verification. As such, the SDT believes that the Transmission Planning entity is the correct entity assigned. Also, it should be noted that the SDT did reference the Planning Coordinator in the Requirements as appropriate.		
Luminant Power	No	In ERCOT the Generation Owner should be responsible. This is a NERC Functional model issue, and I understand the GOP will be responsible in the majority of the country.
Response: Thank you for your comment. Based on comments from industry, your comment, and on guidance from the FMWG, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Exelon Corporation	No	Exelon believes that model verification should be a coordinated effort between the generator owner and the transmission planner. Transmission planning organizations have the expertise to implement and test the models in software, while the generator owners have the necessary access to the equipment in the field. Most generator owners do not have the software and the necessary personnel with the expertise to perform the modeling and model testing required by this standard.
Response: Thank you for your comments. The SDT agrees that a cooperative effort is required among NERC functional model entities in order to develop a robust excitation system model. As mandated by Reliability Standard process, only one entity is assigned responsibility for excitation system model verification. The SDT believes it has incorporated into the draft standard all necessary interactions with other functional model entities required for ensuring model verification success.		
Southern Company	No	The Generator Owner appears to be the logical choice. GO has the access to the equipment records, GOP may not.
Response: Thank you for your comments. Based on guidance from the FMWG, comments from industry, and your comment, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Consumers Energy Company	No	Generator Owners and Generator Operators do not need or use an excitation system model. This model is

Organization	Yes or No	Question 1 Comment
		properly owned by those who need and use it, i.e., the Transmission Planner or Transmission Owner. The Generator Owner should be responsible only for providing input data for the model. These data include such items as:- Manufacturer (and model, if available) and type of excitation system.- Rise times, reactances, time constants, gains, and saturation factors.- Rotational inertia- Reactive compensation settings, if any.- Power system stabilizer settings, if any.- Other stability schemes, if any.Given periodic verification of these data from the Generator Operator, it should be the responsibility of the Transmission Planner to create a model that meets the needs of the Transmission Planner. Since the Generator Operator doesn't need this model, requiring the Generator Operator to hire consultants to create a model needed by other entities is simply errant nonsense. Has the SDT verified that there are adequate consultants available to meet the 2-year time window for the myriad of Generator Operators who would be tasked with creating a model they do not need?
Response: Thank you for your comments. The SDT understands that no matter who is assigned responsibility in the proposed continent-wide standard, it would potentially change the current business model of the functional entity. The majority of the SDT believes that a generation entity should have both final excitation system model responsibility and authority; Based on the majority of industry comments and guidance from the FMWG, the second draft of the standard assigns responsibility to the Generator Owner. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. Note that existing business practices that utilize Transmission Planners can still exist; the only difference is that the Generator Owner would be ultimately responsible for the excitation system model verification from a compliance perspective. Also, the SDT is proposing an Implementation Plan to allow the Generator Owner time to develop in-house expertise to perform model verification if they do not desire to hire consultants.		
City of Garland, Garland Power & Light - GOP Registered Entity	No	The Generator Owner (GO) should be responsible for model verification. The GO has direct access to the equipment - not the GOP. The GO can schedule any required operational testing with the GOP in the same way that the GO schedules any other operational testing requirement. In addition, the GOP and the GO can be two separate companies with their only relationship established by contract. In these situations this standard, as written, would place the burden on the GOP to try to renogoiate the contract with the GO to cover the expense and pursuade the GO to perform the model verification when the real responsibility belongs to the GO.
Response: Thank you for your comments. As recommended, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
American Wind Energy Association	No	Because Generator Operators typically do not have in-house expertise and would have to either hire consultants to perform model verification, or develop in-house expertise including acquiring simulation software, I think it makes more sense for Transmission Planners to perform this activity.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. Also, the Transmission Planner has expertise in overall power system simulation analysis but not necessarily expertise in specific excitation control system modeling. While the Transmission Planner can continue to participate in model verification to whatever extent agreements with the generator entity stipulates, the majority of the SDT (and industry, based upon comments received) does not believe the Transmission Planner should be responsible for this activity.		
American Electric Power	No	AEP believes that It would be more appropriate to designate the Generator Owner for these responsibilities.
Response: Thank you for your comment. The SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Wisconsin Electric	No	See response to Question 5. Providing model data and parameters is possible, but the requirement to validate the model for an actual switching event requires a cooperative effort between the GOP and the TP/TOP/TP. Since the stability and reliability of the overall transmission system is the goal, it is necessary for these entities to have more responsibility for proper excitation system modeling. As it stands this draft standard puts all the responsibility on the GOP.
Response: Thank you for your comments. The SDT agrees that a cooperative effort is required among NERC functional model entities in order to develop a robust excitation system model. As mandated by Reliability Standard process, only one entity is assigned responsibility for excitation system model verification. The SDT believes it has incorporated into the draft standard all necessary interactions with other functional model entities required for ensuring model verification success. For the specific example referenced regarding verification of an event, the SDT believes the currently drafted standard would facilitate cooperation. Specifically, drafted Requirement R8 (reference Requirement R2 in the revised standard) does allow for the equipment's recorder response to be the result of a measured system disturbance. However, it should be pointed out that a pure "switching event" may not result in a voltage deviation of sufficient magnitude at the terminals of the generator.		
Progress Energy, Inc.	No	The Generator Owner is the correct entity for this responsibility. It must be the entity that would be the most able to obtain the attention of the manufacuturer and have the means to accomplish the validation. The entity must have the financial incentives to perform the function and must be knowledgable about the plant operation. The entitiy that would be the best source to coordinate the testing could be required to verify the models. In our opinion the functional model specifies Generator Owner as it requires a generator owner to "verify generating facility performance characteristics". For the foregoing reasons this responsibility should not be assigned to the Transmission Planner.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. The SDT agrees that the Transmission Planner is not the appropriate entity to be responsible for model verification. Based on your comment, other comments from industry, and input from the FMWG, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Dynegy	No	The Generator Owner does not need or use an excitation system model. The Transmission Planner is the entity that uses and needs this model to be accurate. The Generator Owner should be responsible for collecting and providing the generator related input data for the model to the Transmission Planner. The Transmission Planner should be responsible for running the simulations required for model verification and making the judgment if the model's response matches the actual response.
Response: Thank you for your comments. It is in the best interest of all parties, transmission and generation, to develop an accurate excitation system model as these models ultimately result in the determination of acceptable secure conditions for the generator to operate. The majority of the SDT believes that the generation entity should have both final excitation system model responsibility and authority. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. This makes it prohibitive for the Transmission Planner to resolve issues regarding a mismatch between the predicted model response and the actual equipment's recorded response.		
Northeast Utilities	No	The Generator Owner is the correct Functional Model entity that has direct access to the equipment and the authority to perform testing of equipment. All responsibilities assigned to the Generator Operator in the proposed standard should be reassigned to the Generator Owner.
Response: Thank you for your comments. Based on your comment, other comments from industry, and input from the FMWG, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
ISO New England Inc.	No	The Generator Operator has the greatest ability to develop and/or provide accurate models and model parameters for its equipment. The Generator Owner should also be involved in the verification process as required. The process should ideally allow interations between the GO and TO to allow for needed adjustments to model compatability issues and settings with the GO, It should be field verified data not just a self certification of data without the field verification.
Response: Thank you for your comments. The SDT obtained guidance from the FMWG, and as a result of that guidance and other industry comments, the second draft standard assigns responsibilities to the Generator Owner instead of the Generator Operator. The SDT agrees there must be interaction between transmission and generation entities; and has attempted to capture these interactions in the Requirements.		

Organization	Yes or No	Question 1 Comment
Ameren	No	(1)Generator Operators and Generator Owners both should be included in this standard. The entitiy that would be the best source to coordinate the testing could be required to verify the models. It is possible that all functions can not be performed by the Generator Operator alone. Therefore it would be prudent to include the Generator Owners within MOD-026-1. (2) Additionally, the GO would be able to obtain the attention of the manufacuturermanufacturer than GOP. In our opinion the functional model specifies Generator Owner as it requires a generator owner to "verify generating facility performance characteristics". In any case, this responsibility should not be assigned to the Transmission Planner. (3) On the other hand, GO/GOP should not perform the function of modeling or verifying dynamic simulations on the Bulk Electric System which generally is done by Transmission Planners. Generator Operators/Generator Owners should provide the data needed for model simulation. Generator Operators/Generator Owners do not possess the expertise or have the resources to perform modeling simulations.
Response: Thank you for your comments. The SDT believes only one entity can be assigned responsible for model verification. Based on comments from industry, Item 2 of your comments, and input from the FMWG, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard. It is anticipated that the Generator Owner could delegate model verification activities to the Generator Operator by contractual agreement as appropriate. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits.		
AESO	No	The AESO agrees with the SRC ISO/RTO comments.
Response: Thank you for your comment. Please see the response to the SRC IRO/RTO comments.		
Duke Energy	No	Based on Responsibilities in the Functional Model, responsibility for determining maintenance and verification activities is clearly assigned to the Generator Owner. It should also be noted that in some cases the GO may be able to obtain additional expertise from their TP, RTO, or Region, which adds other resource options.
Response: Thank you for your comments. We agree. With guidance received from the FMWG, the Generator Owner is considered the appropriate entity for assigning model responsibility and this change is reflected in the second posting of the draft standard. The SDT agrees that the Generator Owner can seek expertise from others including the entities listed in your observation.		

Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie (HQT)	No	The Generator Operator does not have direct access to the equipment. The Generator Owner is the correct Functional Model entity that has direct access to the equipment and the authority to perform testing of equipment. All responsibilities assigned to the Generator Operator in the proposed standard should be reassigned to the Generator Owner.
Response: Thank you for your comments. We agree. The SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Independent Electricity System Operator	No	This responsibility rests with the Generator Owner. As indicated in the Background Information Section, Generator Owners may be responsible for providing accurate generator data including the excitation data for system modeling. Although it does not operate the generator, verification testing does not need to be performed under operating conditions only. The input/output measurements of the excitation system could suffice to verify the excitation system model, which may be performed during commissioning testing or under other non-production conditions. If the generator must be run by the Generator Operator to enable testing, the Generator Owner can make such an arrangement with the Generator Operator under an agreement, as the Background Information so suggests.
Response: Thank you for your comments. The SDT obtained guidance from the FMWG. Based on this guidance, your comments, and other industry comments, The SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Brazos Electric Power Cooperative	No	Even though a Generator Operator could possible supply and verify the information, it should be the Generator Owner who owns equipment design information that is responsible for it and be directly responsible for compliance with the requirements.
Response: Thank you for your comments. The SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
US Bureau of Reclamation	No	We believe the Generator Owner should be responsible for model verification. The existing NERC Standard, MOD-012-0 requires the Generator Owner to provide dynamic system modeling and simulation data to the RRO. In addition, MOD-013-0, RRO Dynamics Data Requirements and Reporting Procedures (not FERC approved), requires the RRO to coordinate with the Generator Owner to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze dynamic behavior. As such we believe this standard should be consistent and apply to Generator Owners.In addition, the NERC Reliability Functional Model - Version 4 describes the Generator Owner relationships with other entities including "Provides generator information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and

Organization	Yes or No	Question 1 Comment
		Resource Planner."
Response: Thank you for your comments. The SDT agrees with your reasoning and has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Reliant Energy	No	Generator Operators should not have the sole responsibility alone. With the Generator Operators typically not having the in-house expertise for the model verification, they must not only pay the cost of hiring consultants, but will also carry the burden of significant costs for low capacity factor units when trying to schedule the consultants for unpredicable run times. WECC unit verification testing has resulted in very expensive startup costs for low capacity factor units just to perform a test. There is no cost recovery method for running a unit out of the money to perform this testing.
Response: Thank you for your comments. The SDT is currently proposing an exemption for units with a 5% or less capacity factor. By considering exemption for units with low capacity factor, and the established rating threshold for each interconnection, and also the 10-year periodicity requirement defined, the SDT believes situations will not occur where units are dispatched only to perform an excitation control system verification test. As mandated by Reliability Standard process, only one entity is assigned responsibility for excitation system model verification. The SDT believes it has incorporated into the draft standard all necessary interactions with other functional model entities required for ensuring model verification success.		
Wisconsin Public Service	Yes	The Generator Owners, instead of Transmission Planners, are the logical entities to verify the proper functioning of the excitation system functions, but not the verifications of hypothetical parameter values of a model used to emulate the exciters' function. The generator Owners should, for example, verify that the AVR holds set terminal voltages under normal operating system conditions, as well as response to system changes in conformance with the stated Response Ratios as designed. This does not mean, however, that it would be necessary to confirm forward gains, transducer time constants, excitation saturation constants, feedback-loop gains and time constants, etc. are indeed of the same value as used in a hypothetical model. This is due to two reasons: 1) the particular model chosen by the transmission planner is known to be an approximation of the facilities' functions, and therefore the parameters are not unique; 2) instrumentations necessary for verification of specific parameters are not generally available in the industry.
Response: Thank you for your comments. Based on comments from industry, your comment, and guidance from the FMWG, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard. The SDT believes that in most cases, the excitation system control model parameters in use accurately represent the equipment. The SDT also believes that instrumentation utilized for model verification is widely available.		
FirstEnergy	Yes	Although we ultimately agree, we have the following comments:1. The Generator Operator should be responsible

Organization	Yes or No	Question 1 Comment
		to verify the dynamic data is accurate for the Generator, Turbine and Excitation system. The ultimate responsibility for the usability and accuracy of the dynamic models and how they perform in relation to the overall system model is the responsibility of the Transmission Planner.2. Genertor operators in a centrally located dispatch office would not have direct access to the equipment. They can only arrange an actual verification test. Details of the units response to a disturbance would need to be gleaned from the Generator Owner's data. It is not appropriate to burden one entity with a potential compliance violation when another entity controls the data. Relying on agreement coordination between the two entities may not be sufficient to ensure the entity with responsibility to comply is able to comply with an uncooperative entity with data control.
Response: Thank you for your comments. The SDT obtained guidance from the FMWG which recommends assigning this responsibility to the Generator Owner. Also, the majority of the industry agrees that the Generator Owner should be assigned responsibility for model verification. Therefore, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Cowlitz County PUD	Yes	Did you mean to say above that Generator Owners typically do not have in-house expertise and would have to either hire...? YES - Cowlitz as a Generator Owner does not have the in house expertise. Delays result in our efforts to obtain modeling information as we try and find consultants willing to do the work. The Generator Operator is the entity which should be held responsible.
Response: Thank you for your comments. The SDT obtained guidance from the FMWG which recommends assigning this responsibility to the Generator Owner. Also, the majority of the industry agrees that the Generator Owner should be assigned responsibility for model verification. Therefore, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
CenterPoint Energy	Yes	CenterPoint Energy concurs with the SDT that this is a reasonable approach.
Response: Thank you for your comment. The SDT obtained guidance from the FMWG which recommends assigning this responsibility to the Generator Owner. Also, the majority of the industry agrees that the Generator Owner should be assigned responsibility for model verification. Therefore, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Reliant Energy	Yes	Unit operation not unit ownership impacts the reliability of the grid.
Response: Thank you for your comment. The SDT obtained guidance from the FMWG which recommends assigning this responsibility to the Generator Owner. Also, the majority of the industry agrees that the Generator Owner should be assigned responsibility for model verification. Therefore, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		
Indiana Municipal Power Agency	Yes	IMPA recognizes that the Generator Operator can work with the Transmission Planner when it comes to using

Organization	Yes or No	Question 1 Comment
		the verified data in a proper model or simulation software program. This assistance from the Transmission Planner might mean that the Generator Operator does not need to purchase modeling software.
Response: Thank you for your comments. Based on comments from industry and guidance from the FMWG, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard. The SDT agrees with your statement that agreements between the Transmission Planner and the Generator Owner can be arranged for the Transmission Planning entity to perform portions of the model verification process however responsibility for model verification remains with the Generator Owner.		
Xcel Energy	Yes	
Southwest Power Pool Generation Working Group	Yes	
Kansas City Power & Light	Yes	
FEUS	Yes	
Constellation Power Generation & Constellation Nuclear	Yes	
E.ON U.S.	Yes	
AWEA	Yes	
Arizona Public Service Co.	Yes	
Manitoba Hydro	Yes	
Southern California Edison	Yes	
American Transmission Company	Yes	
Response: Thank you for your comments. The SDT obtained guidance from the FMWG which recommends assigning this responsibility to the Generator Owner.		

Organization	Yes or No	Question 1 Comment
Also, the majority of the industry agrees that the Generator Owner should be assigned responsibility for model verification. Therefore, the SDT has assigned responsibility for model verification to the Generator Owner instead of the Generator Operator in the second draft of the standard.		

2. The SDT recognizes that depending on the technology of the modeled equipment, the periodicity of model verification necessary to ensure accurate models could vary. Also, the team recognizes that the majority of the resulting reliability benefit will occur during the initial verification. The SDT determined that 10 years would be an appropriate period for re-verification in the absence of other activities listed in Requirement R12 that would require an earlier re-verification.

Do you agree that 10 years is an appropriate period for re-verification? If you recommend a different period, please state your reasoning.

Summary Consideration:

The majority of industry agreed that the proposed 10 year periodicity verification cycle is appropriate. Therefore, the SDT will maintain the 10-year periodicity verification cycle proposed in the draft standard.

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
Kansas City Power & Light	No	The Electric Power Research Institute has issued a report, "Power Plant Modeling and Parameter Derivation for Power System Studies", number 1015241, Final Report, June 2007; a reasonable interpretation of that work is that there may not be sufficient benefits from using a highly complex model to overcome the potential risks of the testing needed to verify the most complex models. Prototype test data obtained by manufacturers to provide the initial data, in many cases, simply can not be duplicated on operating / operational equipment. The 10 year re-verification requirement, as presently written, does not appear to allow generator owners the necessary flexibility to determine, similar to the regulatory model of 10 CFR 50.59 "Changes, Tests, and Experiments", how detailed the "re-verification" activities need to be. The requirement to re-perform the same bank of physical tests used to originally validate the generator model, absent a physical modification, does not allow sufficient flexibility to perform only those "re-verification" activities for those model parameters whose change due equipment aging has discernable effect on the outcome of the analysis using the generator model. Please note that the concern for performance of tests with little discernable analytical benefit was previously voiced in the "MAAC Position Paper on Generator Testing to Verify Data Required for System Modeling" in the Phase III-IV Planning Standards comments, which can be found on the NERC www site, where the issue of testing nuclear units in compliance with the regulatory requirements of 10 CFR 50.59 was also noted.As a result, it is recommended the SDT consider removing all references in the requirements for periodic testing when no physical changes have taken place and clarify R12 reflects to reverify the parts of the modeling affected by a change and not a reverification of

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
		the entire model. In addition, although the reason to verify generator modeling is logical, it is requested the SDT consider the references stated above and consider the removal or modification of requirements involving testing that place an unncessary risk of generator damage. As an example, allowing vendor simulations or other testing methods by the Vendor in a suitable testing environment to suffice for obtaining generator response characteristics.
Response: Thank you for your comments. The SDT does not believe that there is undue risk to a plant for properly executed excitation system model verification. The validation can also be done using ambient monitoring with no additional tests. The 10-year requirement for re-verification is also overwhelmingly supported by the industry. In any event, there is no requirement to “re-perform the same bank of physical tests.”		
FirstEnergy	No	10 years for digital excitation systems and 5 years for non-digital excitation systems.
Response: Thank you for your comments. The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. The revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
Entergy Fossil Operations	No	I am OK with 10 years for analog systems. Newer digital systems should not change over time, so they should be tested upon commissioning and that should be adequate for the life of the unit.
Response: Thank you for your comments. The SDT believes that 10 years is a reasonable re-verification requirement even for digital systems, even if model verification is based on a sister unit. This position is supported by an overwhelming majority of comments received from the industry.		
IRC Standards Review Committee	No	While a 10 year re-verification period may be adequate for those exciters whose settings do not tend to drift over time, a shorter period, say 5 years, should apply in general since there are analog and rotating type of exciters whose settings tend to drift from time to time.
Response: Thank you for your comments. The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. The revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
E.ON U.S.	No	E.ON U.S. believes that verification data and model results should not change over time. Therefore, a re-verification schedule is not necessary. E.ON U.S recommends that verification be required whenever new equipment is installed.
Response: Thank you for your comments. The SDT believes that 10 years is a reasonable re-verification period. Re-verification does not necessarily require a re-test and in most instances, ambient monitoring can also be used. The proposed 10 year re-verification period is also supported by an overwhelming majority of comments received from the industry.		

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
American Electric Power	No	AEP believes that the period should be longer. In fact, verification should only need to be done once on older units that do not now have good commissioning test documentation. Beyond that, it should only need to be done if there is an applicable equipment upgrade or an intentional readjustment of settings. We question predicating the periodicity on the expectation of a significant variation in equipment performance due to aging alone.
Response: Thank you for your comments. The SDT believes that 10 years is a reasonable re-verification period. Re-verification does not necessarily require a re-test and in most instances, ambient monitoring can also be used. The proposed 10 year re-verification period is also supported by an overwhelming majority of comments received from the industry.		
Reliant Energy	No	The period for re-verification should be based on observed performance, by activities that could result in an alteration of equipment performance or as listed in Requirement R11 which could trigger a review includes Plant Digital Control System (DCS) additions, replacements, or software alterations. Plant DCS activities would only be relevant to excitation system modifications if they involved the addition, deletion, or modification of an outer loop control (such as power factor or reactive power set point) that alters automatic voltage regulator action. If it ain't broke don't fix it!
Response: Thank you for your comments. The SDT believes that 10 years is a reasonable re-verification period. Re-verification does not necessarily require a re-test and in most instances, ambient monitoring can also be used. The proposed 10 year re-verification period is also supported by an overwhelming majority of comments received from the industry. Also, several SDT team members have observed that DCS changes can affect excitation system performance within the timing cycle of the excitation system model..		
ISO New England Inc.	No	We recommend validation on a 5 year scale. 10 years is too long if changes are made to settings during annual outages. The whole approach of the draft standard is a bit flawed because once the model and tuned parameters are verified, no control setting changes should be made to the physical equipment without consulting with the TO to determine their acceptability. Additionally, updates should be provided if the manufacturer or GO identify improvements to the model in regard to matching the actual equipment. Having a verification in addition to the preceding is acceptable and would provide the benefit of having a written documentation from the GO and better assure that acccurate models are being used for planning the system.
Response: Thank you for your comments. The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. The revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
Ameren	No	(1) Many generating units are now on six year outage cycles, therefore we recommend the interval is changed to 12 years or more.(2) Concerns regarding excitation equipment are that someone at the plant may inadvertently modify settings on dials/potentiometers at some point within a 10/12 year period (or other interval that would be considered appropriate) that would cause the performance of the exciter to vary from what was originally specified in the dynamic model representation. Also, it is possible that, through aging, electrical values of circuit components in the excitation equipment could drift, even with no external change to the settings. It is uncertain what the re-verification period should be to minimize these effects, so we support the caveats listed in Requirement 11 and 12. However, despite R12, some communication between the Generation Operator and the Transmission Operator within the 10/12 year period would be reassuring that nothing has changed. Because 10/12 years is a long time, the Generator Owner should be required to respond upon request of the Transmission Planner confirming that nothing has changed. Further, the second bullet of R11 might also note that the Generation Operator must verify for the model for the first time if the model was derived from a 'sister' unit or repeat the verification on one previously verified.
Response: Thank you for your comments. The SDT believes that 10 years is a reasonable re-verification period. Re-verification does not necessarily require a re-test and in most instances, ambient monitoring can also be used. The proposed 10 year re-verification period is also supported by an overwhelming majority of comments received from the industry. The SDT is not sure of the intent of the last sentence. The SDT does not believe that model verification of each unit is needed if the units satisfy the sister unit definition. The SDT also believes requiring communication for activity that does not change settings or create evidence indicating setting have changed is an unnecessary burden. However, if an activity is performed that could change settings or creates evidence of setting changes, then the revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
AESO	No	The AESO agrees with the SRC ISO/RTO comments. We would also like to add: WECC requirements state every 5 years. 5 years seems more resonable than 10 years to ensure that the generating unit is still performing as intially sepceified and there has been no no component degradation causing the settings to drift.
Response: Thank you for your comments. The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. The revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
Duke Energy	No	It would seem that the need to revalidate is driven by technical issues (analog controls drift, digital doesn't). There is an EPRI guide (1004556) that specifies a 5 year frequency for analog AVR calibrations. The SDT should discuss different periods based upon different control technologies (e.g. digital versus analog).In addition to R12, some communication between the Generation Operator and the Transmission Operator within the 10 year period would be reassuring that nothing has changed.
Response: Thank you for your comments. The SDT believes that 10 years is a reasonable re-verification period. Re-verification does not necessarily require a		

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
re-test and in most instances, ambient monitoring can also be used. The proposed 10 year re-verification period is also supported by an overwhelming majority of comments received from the industry. The SDT also believes requiring communication for activity that does not change settings or create evidence indicating setting have changed is an unnecessary burden. However, if an activity is performed that could change settings or creates evidence of setting changes, then the revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
American Transmission Company	No	The 10 year period is too long and should be changed to 5 years in order to ensure greater model accuracy.
Response: Thank you for your comment. The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. The revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
US Bureau of Reclamation	No	We believe the 10 year period is too long. It is hard to make the case for reliability-based need for this standard when 10 years are allowed to complete the modeling. Suggest changing the initial implementation period to 5 years which is the implementation period provided in the WECC regional policy. Ten years may then be appropriate for re-validation.
Response: Thank you for your comments. The purpose of the initial 10-year implementation period is to give industry sufficient time to perform verification on required units with limited expertise available. The SDT believes that 10 years is a reasonable re-verification period. Re-verification does not necessarily require a re-test and in most instances, ambient monitoring can also be used. The proposed 10-year re-verification period is also supported by an overwhelming majority of comments received from the industry.		
Independent Electricity System Operator	No	We believe a 10 year re-verification period is adequate for those exciters whose settings do not tend to drift over time. However, a shorter period, say 5 years, should apply to the analog or rotating type of exciters.
Response: Thank you for your comments. The SDT believes that with Requirements R11 and R12 in the original posting (reference Requirements R3 and R4 in the revised standard) in place, a 5 year re-verification period is unnecessary, even for analog and rotating exciters. This position is also supported by an overwhelming majority of comments received from the industry. The revised requirement R4 (reference footnote) 1 contains provision for earlier re-verification if such a need is justified.		
NERC Event Analysis & Information Exchange staff	Yes	Ten years is an adequate backstop for re-testing. However, it should additionally be tempered by performance differences observed during validation to actual or staged system events. Repeated matching of model performance to events should also make a ten year test unnecessary.
Response: Thank you for your comments. The overwhelming majority of the comments received from industry support a 10-year re-verification period. The SDT agrees that the repeated matching of model performance to events can be acceptable verification however, the required data must be submitted every 10 years to		

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
ensure that proper verification has been completed.		
Northeast Power Coordinating Council	Yes	A ten-year interval is acceptable given the conditions in Requirement R12.
Response: Thank you for your comment.		
SERC Dynamics Review Subcommittee (DRS)	Yes	We agree as long as there is a requirement such as R11. The second bullet of R11 might also note that the Generation Operator (Owner) must verify the model for the first time if the model was derived from a 'sister' unit or repeat the verification on one previously verified. Despite R12, some communication between the Generation Operator (Owner) and the Transmission Operator, within the 10 year period stating that nothing has changed would be reassuring. Because 10 years is a long time, the Generator Owner should be required to respond if requested by the Transmission Planner confirming that nothing has changed.
Response: Thank you for your comments. The SDT is not sure of the intent of the second sentence. The SDT does not believe that model verification of each unit is needed if the units satisfy the sister unit definition. The SDT also believes requiring communication for activity that does not change settings or create evidence indicating setting have changed is an unnecessary burden. However, if an activity is performed that could change settings or creates evidence of setting changes, then the revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
Progress Energy, Inc.	Yes	As long as there is a requirement such as R11. The second bullet of R11 might also note that the Generation Operator must verify for the model for the first time if the model was derived from a 'sister' unit or repeat the verification on one previously verified. Despite R12, some communication between the Generation Operator and the Transmission Operator within the 10 year period would be reassuring that nothing has changed. Because ten years is a long time, the Generator Owner should be required to respond upon request of the Transmission Planner confirming that nothing has changed.
Response: Thank you for your comments. The SDT is not sure of the intent of the second sentence. The SDT does not believe that model verification of each unit is needed if the units satisfy the sister unit definition. The SDT also believes requiring communication for activity that does not change settings or create evidence indicating setting have changed is an unnecessary burden. However, if an activity is performed that could change settings or creates evidence of setting changes, then the revised Requirements R3 and R4 contain provisions for performing re-verification earlier if justified.		
Northeast Utilities	Yes	Consider the need to account for wind turbine generation that does not have mature models for this verification - therefore a shorter period may apply to accommodate improvements of those models.
Response: Thank you for your comments. The MVA thresholds in the Applicability section of the first posting of MOD-026 resulted in wind powered units not being		

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
subject to this standard because no single wind unit is rated greater than 20 MVA. However, there is an increasing number of wind farms with significantly larger aggregate MVA. As such, their impact on the reliability of the Bulk Electric System cannot be ignored – otherwise, a reliability gap would be created. Therefore, based on your comments and other industry comments, the SDT discussed the possibility of requiring verification of dynamic models that represent the aggregate of numerous small units and any necessary auxiliary equipment as required due to the technology of the small units. This could include plant dynamic voltage control and reactive support of all the units and auxiliary equipment (such as individual WTG response, plant-wide volt/var controller response, and response from separate volt/var regulation devices contained in the plant, such as SVC/STATCOM/Synchronous Condenser) contained in any technology generation plant, including a wind farm (plant), that exceeds appropriate aggregate nameplate MVA threshold. There are dynamic models that adequately replicate wind unit performance for some wind units today. However, there are many existing wind units for which there are no publicly available models supplied by the Original Equipment Manufacturer. Generic wind models (i.e., type I, II, III and IV) are in various stages of development. Also, there are ongoing efforts involving Regional Entities and manufactures to close any large gaps that may exist in current generic models. Given that there will be significant time between now and the time that this standard could be approved by FERC, it is expected that generic wind farm (plant) models will reach an appropriate state of maturity for establishing boundary conditions in Bulk System Studies. In order to mitigate the reliability gap, the Applicability section will be expanded in the second posting of the standard to include significant MVA percentage of all generation for all technologies.		
Exelon Corporation	Yes	It is difficult to determine whether or not 10 years is an appropriate period for re-verification without knowing the details of the required testing.
Response: Thank you for your comment. The SDT believes that 10 years is a reasonable re-verification period. Re-verification does not necessarily require a re-test and in most instances, ambient monitoring can also be used. The proposed 10 year re-verification period is also supported by an overwhelming majority of comments received from the industry		
Southern Company	Yes	Years of operating experience has shown that existing excitation systems that are properly maintained typically do not deteriorate to the point where performance is noticeably impacted in less than 10 years.
Response: Thank you for your comment.		
Hydro-Québec TransEnergie (HQT)	Yes	ten-year interval is acceptable given the conditions in Requirement R12.
Response: Thank you for your comment.		
CenterPoint Energy	Yes	CenterPoint Energy concurs periodic verfication every ten years is appropriate.

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
Response: Thank you for your comment.		
Consumers Energy Company	Yes	Ten years is appropriate with the caveats listed in Requirement 12.
Response: Thank you for your comment.		
Manitoba Hydro	Yes	
Dynegy	Yes	
Xcel Energy	Yes	
Southern California Edison	Yes	
Indiana Municipal Power Agency	Yes	
Brazos Electric Power Cooperative	Yes	
Southwest Power Pool Generation Working Group	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Pepco Holdings, Inc (PHI) - Affiliates	Yes	
FEUS	Yes	
Luminant Power	Yes	

Organization	Yes or No	Question 2 Recommended Periodicity and Reasoning:
Constellation Power Generation & Constellation Nuclear	Yes	
Cowlitz County PUD	Yes	
Wisconsin Public Service	Yes	
City of Garland, Garland Power & Light - GOP Registered Entity	Yes	
AWEA	Yes	
American Wind Energy Association	Yes	
Arizona Public Service Co.	Yes	
Wisconsin Electric	Yes	
Reliant Energy	Yes	

3. The SDT thought that it would be reasonable to apply a philosophy to allow maximization of limited resources required to perform excitation system model verification. The philosophy allows a single unit's actual excitation system verification to be a proxy for multiple units if the following conditions are met: a) the units have the same MVA rating, b) the units are rated at ≤ 250 MVA c) the units have identical applicable components and settings and d) the units are sited at the same physical location. For each recurring 10 year cycle, another unit must actually be verified.

Do you agree with the proxy unit approach as used in Requirement R1 Item 2? If not, please explain.

Summary Considerations:

The majority of respondents agreed with using the proxy unit approach. There were several suggested adjustments to the proxy unit approach criteria proposed. The most requested adjustments was to increase the unit MVA size threshold from 250 MVA to 350 MVA. The SDT updated the second draft of the standard to reflect a unit MVA size threshold of 350 MVA; with language contained in the attached periodicity Attachment.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	Unit testing has in the past identified different responses from identical units with common settings. All units with identical design and settings should be tested unless records of actual system events demonstrate that all of the units respond the same.
Response: Thank you for your comments. Previous experience is noted. However, given the limited resources available for industry to execute necessary test and analysis work, the SDT believes that it is not practical to require testing of all units described as proxy units. This conclusion is supported by the majority of comments received from the industry as indicated in the Summary Considerations section above. The SDT notes that Requirement R11 (reference Requirement R3 in the revised standard) requires any unit (including those considered as "proxy" units) to be fully tested/analyzed if unit performance during a system event does not match predicted response.		
SERC Dynamics Review Subcommittee (DRS)	No	We encourage the proxy unit approach. However, we do not agree completely to the conditions illustrating the proxy unit approach. (1) "MVA rating" should be changed to say "MVA nameplate rating". We believe it would be prudent to specify that units of different manuafacturers are not proxy units, even if they have the same nameplate rating, (2) If the units are identical, we believe the 250 MVA threshold criterion is too restrictive. We believe the threshold should be at least 350 MVA to cover combined cycle units using existing technology.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also accepts the		

Organization	Yes or No	Question 3 Comment
recommendation to incorporate the term "MVA Nameplate Rating" in the second draft of the standard. With respect to the "different manufacturers" issue, the SDT believes the language, "and if they have identical applicable components and settings", contained in the original Standard draft provides sufficient specificity on this point. We note both you and several industry responders, proposed increasing the MVA Nameplate Rating threshold to 350 MVA. The SDT agrees with the reasoning, "to cover the steam unit of multiple combined cycle plant sites using existing technology", stated for this change and has modified the standard accordingly.		
FirstEnergy	No	1. While we agree with this approach, we do not agree it should be limited to 250 MVA units. It should allow it for any identical units of any size. Also, the requirement could be written more clearly by revising it to make it clear that verification is for similar units only and not all units owned. Based on these comments, we suggest re-wording R1 (2) to state: "For an existing unit, once in a ten calendar year period. If multiple units have identical applicable components and settings and are sited at the same physical location, verification of one unit is sufficient for all of these units. Verification shall be performed on a different unit each ten calendar year cycle."2. This is a lot like the "Sister Unit" concept developed in the recent RFC generator verification standards. It may be helpful if this term was defined and described in more detail in the standard to allow for ease of compliance verification.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also notes the recommendation to make the MVA Nameplate Rating threshold limitless, and while this recommendation was received by several responders, the SDT does not believe this recommendation represents the majority opinion of Industry. The SDT is also of the opinion that significantly large units can have a substantial impact on BES security and therefore an unlimited MVA threshold is not appropriate. The SDT has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders. The SDT has noted the recommendation to more clearly define the "proxy (or sister) unit" concept and points out that the actual standard does not use either of these terms and simply states the requirements; which have been moved to the attached Periodicity Attachment in the second standard draft.		
Pepco Holdings, Inc (PHI) – Affiliates	No	A GOP (or GO) may have sister units (identical units) at diffrent locations. This should not be restricted to one location.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.		
Exelon Corporation	No	Why there is a limitation of unit size of 250MVA or less. The proxy unit approach should be extended to identical units of any size for a two unit station as half of the capacity at that station has been verified as

Organization	Yes or No	Question 3 Comment
		compared to a multi unit site say having 6 250MVAs and verifying only one unit.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also notes the recommendation to make the MVA Nameplate Rating threshold limitless, and while this recommendation was received by several responders, the SDT does not believe this recommendation represents the majority opinion of Industry. The SDT is also of the opinion that significantly large units (> 250 MVA) can have a substantial impact on BES security and therefore an unlimited MVA threshold is not appropriate. The SDT has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders.		
Southern Company	No	Agree with all requirements except b and d. If the GO/GOP has duplicate units at multiple sites , a re-verification test of one unit should apply to all provided they meet items a and c. The size of the unit (b) nor the physical location (d) do not matter. The MVA rating of the machine should not be an excluding factor for units of the same vintage, rating, manufacturer, and with the same type of excitation system and settings.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also notes the recommendation to make the MVA Nameplate Rating threshold limitless, and while this recommendation was received by several responders, the SDT does not believe this recommendation represents the majority opinion of Industry. The SDT is also of the opinion that significantly large units (> 250 MVA) can have a substantial impact on BES security and therefore an unlimited MVA threshold is not appropriate. The SDT has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders. The SDT respectfully maintains that the “same physical location” requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the “same physical location” requirement is necessary.		
E.ON U.S.	No	E.ON U.S. does believe that the proxy process described is reasonable. As expressed in the response to question 2, E.ON U.S. believes that, absent installation of new equipment, a re-verification schedule is unnecessary.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT maintains that the proposed re-verification schedule is appropriate to provide a means to capture changes in excitation system equipment due to component aging, calibration drift, etc.		
Wisconsin Public Service	No	The sister unit philosophy should be applied to identical units within a generator operators fleet with identical settings, but not be limited to the same physical site.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.		
Wisconsin Electric	No	We believe that units rated up to 850 MVA should be able to take advantage of this approach.
Response: Thank you for your comment. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also notes the recommendation to increase the MVA Nameplate Rating threshold to 850 MVA, and while this recommendation was received by several responders, the SDT does not believe this recommendation represents the majority opinion of Industry or that the threshold should be this high. The SDT has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders.		
American Electric Power	No	While AEP agrees that the proxy approach to verify multiple, identical units based on system model verification for a single unit makes sense, it is unclear why criterion "b" (the units are rated at less than or equal to 250MVA) would apply, provided criteria "a", "c", and "d" are also met. It is suggested that criterion "b" as listed in the Comment Form and as referenced in Requirement R1.2 be removed from the Standard.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also notes the recommendation to remove the MVA Nameplate Rating threshold, and while this recommendation was received by several responders, the SDT does not believe this recommendation represents the majority opinion of Industry. However, based on industry comments, the SDT has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders.		
Progress Energy, Inc.	No	We encourage the proxy unit approach. However, we do not agree completely to the conditions illustrating proxy unit approach. (1) MVA rating should be expanded to say "MVA nameplate rating" . We believe it would be prudent to specify that units of different manuafacturers, even if they have the same nameplate rating are not proxy units, (2) If the units are identical, we believe the 250 MVA threshold criterion is too restrictive. We believe the limit should be at least 350 MVA to cover combined cycle units of existing technology.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also accepts the recommendation to incorporate the term "MVA Nameplate Rating" in the second draft of the standard. With respect to the "different manufacturers" issue, the SDT believes the language, "and if they have identical applicable components and settings", contained in the original Standard draft provides sufficient specificity on this point. We note both your comment and several industry responders propose increasing the MVA Nameplate Rating threshold to 350 MVA. The SDT agrees with the		

Organization	Yes or No	Question 3 Comment
reasoning, “to cover the steam unit of multiple combined cycle plant sites using existing technology”, stated for this change and has modified the standard accordingly.		
Northeast Utilities	No	Units testing has in the past identified different responses from identical units with common settings. All units with identical design and settings should be tested unless records of actual system events demonstrate that all of the units respond the same.
Response: Thank you for your comments. Previous experience is noted. However, given the limited resources available for industry to execute necessary test and analysis work, the SDT believes that it is not practical to require testing of all units described as proxy units. This conclusion is supported by the majority of comments received from the industry as indicated in the Summary Considerations section above. The SDT notes that Requirement R11 (reference Requirement R3 in the revised standard) requires any unit (including those considered as “proxy” units) to be fully tested/analyzed if unit performance during a system event does not match predicted response.		
Hydro-Québec TransEnergie (HQT)	No	Units testing has in the past identified different responses from identical units with common settings. All units with identical design and settings should be tested unless records of actual system events demonstrate that all of the units respond the same.
Response: Thank you for your comments. Previous experience is noted. However, given the limited resources available for industry to execute necessary test and analysis work, the SDT believes that it is not practical to require testing of all units described as proxy units. This conclusion is supported by the majority of comments received from the industry as indicated in the Summary Considerations section above. The SDT notes that Requirement R11 (reference Requirement R3 in the revised standard) requires any unit (including those considered as “proxy” units) to be fully tested/analyzed if unit performance during a system event does not match predicted response.		
AESO	No	The AESO believes that using a single unit’s actual excitation system verification to be a proxy for multiple units will not pick up errors in settings, component failures, alterations to units, etc. Each unit should be tested individually.
Response: Thank you for your comments. Previous experience is noted. However, given the limited resources available for industry to execute necessary test and analysis work, the SDT believes that it is not practical to require testing of all units described as proxy units. This conclusion is supported by the majority of comments received from the industry as indicated in the Summary Considerations section above. The SDT notes that Requirement R11 (reference Requirement R3 in the revised standard) requires any unit (including those considered as “proxy” units) to be fully tested/analyzed if unit performance during a system event does not match predicted response.		
NERC Event Analysis & Information Exchange staff	Yes	As long as no actual differences are observed during performance comparisons to actual system events, this is an acceptable shortcut.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The SDT believes that the situation described will be satisfied by Requirement R2 in the revised standard.		
Entergy Fossil Operations	Yes	I agree with this except for the less than or equal to 250 MVA. It should apply to all units meeting the sister unit criteria regardless of MVA. If you want a limit, then make it something higher like 80% of the single largest generator in the system.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also notes the recommendation to increase the MVA Nameplate Rating threshold 80% or higher of the largest system generator, and while this recommendation was received by several responders, the SDT does not believe this recommendation represents the majority opinion of Industry. The SDT is also of the opinion that significantly large units (> 250 MVA) can have a substantial impact on BES security and therefore an unlimited MVA threshold is not appropriate. The SDT has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders. The SDT respectfully maintains that the “same physical location” requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the “same physical location” requirement is necessary.		
Ameren	Yes	We encourage the proxy unit approach. However, we do not agree completely to the conditions illustrating proxy unit approach. (1) MVA rating should be expanded to say "MVA nameplate rating" . We believe it would be prudent to specify that units of different manuafacturers, even if they have the same nameplate rating are not proxy units. Further, turbine rating should also be considered as appropriate. (2) If the units are identical, we believe the 250 MVA threshold criterion is too restrictive. We believe the limit should be at least 350 MVA to cover combined cycle units of existing technology.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also accepts the recommendation to incorporate the term “MVA Nameplate Rating” in the second draft of the standard. With respect to the “different manufacturers” issue, the SDT believes the language, “and if they have identical applicable components and settings”, contained in the original Standard draft provides sufficient specificity on this point. We note both your comment and several industry responders propose increasing the MVA Nameplate Rating threshold to 350 MVA. The SDT agrees with the reasoning, “to cover the steam unit of multiple combined cycle plant sites using existing technology”, stated for this change and has modified the standard accordingly.		
Duke Energy	Yes	If it could be verified that the Gains and TCs are exactly the same, but just reading dial settings on analog controls might not suffice. For digital, the gains are the number programmed in, so the proxy approach is

Organization	Yes or No	Question 3 Comment
		more reasonable.Also, recommend changing MVA rating to 350 MVA so that combined cycle steam units are included.
Response: Thank you for your comments. Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT accepts this recommendation and has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders.		
Independent Electricity System Operator	Yes	We agree with the proxy unit approach only if these units' excitation systems show identical performance based on the results of a limited number of tests. On the other hand, we do not agree with the 10-year cycle. Accurate excitation system data and verification that it performs as designed are critical to accurate modeling and simulation to support a wide range of reliability activities, including the determination of SOLs and IROLs. The 10 year recycle period is too long that risks changes to excitation system characteristics undetected. We suggests this period be shortened to 5 years.
Response: Thank you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT maintains that the proposed re-verification schedule is appropriate to provide a means to capture changes in excitation system equipment due to component aging, calibration drift, etc. The SDT notes that Requirement R11 (reference Requirement R3 in the revised standard) requires any unit (including those considered as "proxy" units) to be fully tested/analyzed if unit performance during a system event does not match predicted response.		
Reliant Energy	Yes	Proxy unit ratings should go up to 500 MVA.
Response: Thank you for your comment. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT also notes the recommendation to increase the MVA Nameplate Rating threshold to 500 MVA, and while this recommendation was received by several responders, the SDT does not believe this recommendation represents the majority opinion of Industry or that the threshold should be this high. The SDT has increased the Nameplate MVA Rating threshold from 250 MVA to 350 MVA as requested by the majority of industry responders.		
Consumers Energy Company	Yes	This looks to be a "sister unit" type of proxy. If so, it should be introduced as a new definition.
Response: Thank you for your comment. The SDT notes that the actual standard does not use either of these terms but simply states the requirements; which have been moved to the attachment Periodicity Attachment in the second draft of the revised standard.		
Constellation Power Generation & Constellation Nuclear	Yes	The proxy unit approach is quite appropriate for excitation system verification for multiple units.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
IRC Standards Review Committee	Yes	We agree with the proxy unit approach.
Response: Thank you for your comment.		
Reliant Energy	Yes	I can not see any reliability benefit to requiring the verification of sister units.
Response: Thank you for your comment. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT maintains that the proposed re-verification schedule is appropriate to provide a means to capture changes in excitation system equipment due to component aging, calibration drift, etc.		
Southwest Power Pool Generation Working Group	Yes	
Dominion	Yes	
Kansas City Power & Light	Yes	
MRO NERC Standards Review Subcommittee	Yes	
FEUS	Yes	
Luminant Power	Yes	
Cowlitz County PUD	Yes	
City of Garland, Garland Power & Light - GOP Registered Entity	Yes	
AWEA	Yes	
American Wind Energy Association	Yes	
Arizona Public Service Co.	Yes	

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Yes	
Dynegy	Yes	
Southern California Edison	Yes	
Indiana Municipal Power Agency	Yes	
ISO New England Inc.	Yes	
CenterPoint Energy	Yes	
Xcel Energy	Yes	
Brazos Electric Power Cooperative	Yes	

4. The list of unit specific information in Requirement R4 to be provided to the Transmission Planner from the Generator Owner includes generator data used in the excitation system verification process. The reason is that the tests, ambient or staged, which are used to verify the excitation system model, are part of a closed loop system that includes the generator. However, the SDT stopped short of requiring verification of either all generator data, or a portion of the generator data which is most applicable to excitation system testing (Transient Open Circuit Time Constant, and for PSS model verification, rotational inertia). The SDT feels that it cannot develop draft Requirements for the verification of generator data without submitting a supplementary SAR to the NERC Standards Committee.

Do you agree with the approach of requiring the Generator Owner to supply the generator data used in the excitation system model verification?

Summary Consideration:

Most responders agreed there is a need for clarity regarding the specific generator data used for exciter data verification, and that it was not necessary to separately verify the generator data. Most responders felt it was appropriate to require Generator Owners to provide the generator data. Clarifying language has been added to the standard in Requirement R2, including specifying that generator data used to verify the excitation control system also be provided with the other data obtained during model verification.

Organization	Yes or No	Question 4 Comment
Southwest Power Pool Generation Working Group	No	The proposed standard states Generator Operator, as opposed to Generator Owner. The Generator Owner should be the one providing the data.
Response: Thank you for your comment. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
Entergy Fossil Operations	No	I may agree if it is reasonable and list exactly what data can be requested by the TP. Remember, the GO is dependent on contractors for doing this, it costs them money, and is of no benefit to the GO, so the listing need to be specific so it can be listed in the job scope of the work and reasonable.
Response: Thank you for your comments. The SDT respectfully disagrees that the generator/exciter model verification is of no benefit to the Generator Owner. Although the primary purpose for model verification is to provide accurate models, there are other significant benefits which the Generator Owner will realize such		

Organization	Yes or No	Question 4 Comment
as: • Without the verification data and resulting system simulation results, transfer capabilities are uncertain and there is greater risk of generator tripping because of system issues. • Generation power sales are dependent on the transmission system transfer capability. • There have been several instances where verification efforts have discovered maintenance issues that, if not identified and corrected, would have resulted in unit tripping and possible equipment damage. The SDT asserts the knowledge and generator data required is inherent to the verification process, and as such requires the expert responsible for providing verification results to specify the required parameter list since this list is dependent on the generator and exciter models selected. It is important that this verification work is performed by individuals familiar with specifying the required parameter list associated with the model selected to best match equipment performance. As such, the SDT believes providing a detailed parameter list in the standard will create confusion.		
Luminant Power	No	Luminant does not disagree that the information needs to be provided. However, the generator model data is already required in NERC Standards MOD-012 adn MOD-013 (R1.2). The Generation Owner should not be held doubly liable for the same information in two Standards. This requirement for the Generator data is already required elsewhere and is not needed in this standard.
Response: Thank you for your comments. Regional requirements will be retired from the NERC standards. MOD-012 and MOD-013 standards do not require verification (unless the region requires it). The purpose of MOD-026 is to require verification. MOD-012 requires submission of both generator and exciter data with other dynamics data provided. Experience has shown that both excitation system data and generator data must be revised when performing the verification process. Even if revisions are not necessary, it is essential that unambiguous generator and exciter data is incorporated into the simulation tools. A simple way to ensure consistency is by requiring both generator data and exciter data be included in the verification report. Information must be updated with generator data included in the exciter verification report.		
Southern Company	No	Since the exciter model and the generator model are components of the closed loop system being verified, the process should ensure that the transmission planners dynamic database is updated with the generator data and the excitation system data utilized for model verification. Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunities for generator data submitted for MOD-012 to be inconsistent with generator data used in the excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator with the unit specific data contained in the Transmission Planner's dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was updated during the process of obtaining a

Organization	Yes or No	Question 4 Comment
		verified excitation system model". These language modifications will help ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.
Response: Thank you for your comments. The SDT agrees with this recommendation and has incorporated the concept into Requirement R3 (Reference Requirement R1 in the revised standard). However, the SDT did not adopt the recommendation for R4 item 2 (Reference Requirement R2, Part 2.1 in the revised standard). To ensure consistency, it is important that the generator model data is always provided with the exciter model data even if it the data has not changed. The SDT does not believe this is a burdensome requirement given the benefit realized by ensuring necessary data is clearly communicated.		
Cowlitz County PUD	No	I think you meant for the Generator Operator to supply the generator data.
Response: Thank you for your comment. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
Indiana Municipal Power Agency	No	IMPA believes the generator data is important and that it is currently being provided per MOD-010 (static) and MOD-012 (dynamic). Another standard requiring this information would put the stakeholder at a double risk factor, and FERC does not believe in this double risk factor.
Response: Thank you for your comments. Regional requirements will be retired from the NERC standards. MOD-012 and MOD-013 standards do not require verification (unless the region requires it). The purpose of MOD-026 is to require verification. MOD-012 requires submission of both generator and exciter data with other dynamics data provided. Experience has shown that both excitation system data and generator data must be revised when performing the verification process. Even if revisions are not necessary, it is essential that unambiguous generator and exciter data is incorporated into the simulation tools. A simple way to ensure consistency is by requiring both generator data and exciter data be included in the verification report. Information must be updated with generator data included in the exciter verification report.		
NERC Event Analysis & Information Exchange staff	No	See below.
Response: Thank you for your comment. Refer to the response provided to the other comment(s).		
Northeast Power Coordinating Council	Yes	The entity specified in Question 4 does not agree with the entity specified in Requirement R4. As stated in our response to Question 1, we believe the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.
Response: Thank you for your comments. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question		

Organization	Yes or No	Question 4 Comment
1.		
SERC Dynamics Review Subcommittee (DRS)	Yes	Since the exciter model and the generator model are components of the closed loop system being verified, the process should ensure that the transmission planners dynamic database is updated with the generator data and the excitation system data utilized for model verification. Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunties for generator data submitted for MOD-012 to be inconsistent with generator data used in the excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator with the unit-specific data contained in the Transmission Planner's dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was changed in order to obtain a verified excitation system model". These language modifications will help ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.
Response: Thank you for your comments. The SDT agrees with this recommendation and has incorporated the concept into Requirement R3 (Reference Requirement R1 in the revised standard). However, the SDT did not adopt the recommendation for R4 item 2 (Reference Requirement R2, Part 2.1 in the revised standard). To ensure consistency, it is important that the generator model data is always provided with the exciter model data even if it the data has not changed. The SDT does not believe this is a burdensome requirement given the benefit realized by ensuring necessary data is clearly communicated.		
Dominion	Yes	We believe that all requirements of this standard should apply to the Generator Owner, not the Generator Operator.
Response: Thank you for your comment. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
FirstEnergy	Yes	The question above has a typographical error. We assume the team means "Generator Operator".
Response: Thank you for your comment. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
IRC Standards Review Committee	Yes	We agree with the approach of requiring the Generator Owner to supply the data listed. We also suggest that since this data is required 90 calendar days of completion of the excitation system model verification - the same condition for providing documentation demonstrating that the excitation system model's response matches the

Organization	Yes or No	Question 4 Comment
		recorded response for a voltage excursion at the generator as stipulated in R8, we suggest R8 be combined with R4. Note that "Generator Owner" instead of "Generator Operator" is used in this question. While we view this as a typo, as indicated in our comment under Q1 we think it is appropriate that the Generator Owners be held responsible for the majority of the requirements in this standard.
Response: Thank you for your comments. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1. The SDT agrees with the recommendation to combine Requirement R8 with R4 (reference Requirement R2, Part 2.1 in the revised standard).		
Consumers Energy Company	Yes	We believe that generator data must be verified; however, the concept of staged tests is troubling as such testing can provide a local challenge to the integrity of the BES. Such testing should be required to be well coordinated with the Transmission Operator. Our experience shows start-up testing of new exciters has occasionally resulted in significant local impact to the transmission system, e.g., over-voltage on 345 kV systems.
Response: Thank you for your comments. There is risk associated with performing staged generation tests however, the SDT believes the benefits outweigh the risks. Exciter verification testing is essential for ensuring accurate dynamic simulations. To mitigate risk to the transmission system, the SDT recognizes that it is important to have testing personnel notify the Transmission Operator of scheduled tests, and interact as needed during the testing evolution.. System security must be maintained during the test. As example, system conditions may require the Transmission Operator to cancel planned testing. Also keep in mind verification requirements include alternatives to performing staged tests such as system performance monitoring under ambient conditions; which would be preferable to performing staged tests in some circumstances. Bench testing may be another viable option. A verification expert can evaluate available alternatives and assist with performing a situation specific risk/benefit assessment.		
City of Garland, Garland Power & Light - GOP Registered Entity	Yes	This same approach should be used for question #1. It is the Generator Owner (GO) that has this information and access to the equipment.
Response: Thank you for your comments. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
Progress Energy, Inc.	Yes	Since the exciter model and the generator model are components of the closed loop system being verified, the process must ensure that the Transmission Planners dynamic database is updated with the generator data and the excitation system data utilized for verification. Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunties for generator data submitted for MOD-012 to be inconsistent with generator data used in models in the excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator the unit specific data contained in the

Organization	Yes or No	Question 4 Comment
		Transmission Planner's dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was changed in order to obtain a verified excitation system model". These language modifications ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.
Response: Thank you for your comments. The SDT agrees with this recommendation and has incorporated the concept into Requirement R3 (Reference Requirement R1 in the revised standard). However, the SDT did not adopt the recommendation for R4 item 2 (Reference Requirement R2, Part 2.1 in the revised standard). To ensure consistency, it is important that the generator model data is always provided with the exciter model data even if it the data has not changed. The SDT does not believe this is a burdensome requirement given the benefit realized by ensuring necessary data is clearly communicated.		
Ameren	Yes	(1) Generator Operators and Generator Owners should be included in this standard. It is possible that all functions can not be performed by the Generator Operator. Therefore it would be prudent to include the Generator Owners within MOD-026-1. (2) If the generator has not been modified, and the manufacturer's data is available, then there should be no need for retesting of the generator. However, if the generator has been modified since the last data set was established for the generator, (stator or rotor turns shorted, rotor replaced, etc.) then re-testing of the generator would be in order. If the turbine has been replaced, then an updated value for rotational inertia would be needed. (3) The concept of staged tests is troubling as such testing can provide a local challenge to the integrity of the BES. Such testing should be required to be well coordinated with the Transmission Operator. (4) Relying on generator data that was originally provided for MOD-012 to be the same data that was used for model verification would not be advisable. There are countless opportunties for generator data submitted for MOD-012 to be inconsistent with generator data used in models in the excitation system verification process. In order to close this loop, we suggest that R3 be slightly modified to read: "The Transmission Planner shall provide the Generator Operator the unit specific data contained in the Transmission Planner's dynamic database from the current in-use excitation system and generator model, including the applicable generator model parameter's MVA base, within 30 calendar days of a request from the Generator Operator." AND R4 Item 2 should have an additional sentence at the end which reads: "This data only has to be provided in those instances where generator model data was changed in order to obtain a verified excitation system model". These language modifications ensure that dynamic databases are populated with the correct data for both the excitation system and generator models that have been verified while minimizing burden on the generation entity responsible for model verification.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. 1) The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1. 2) The SDT agrees that exciter verification will also provide adequate verification of the generator model if test results match simulation results. The SDT also agrees additional effort is required to improve the generator model if results do not match. The SDT has decided that the MOD-026 standard scope is limited to the excitation system because standard development would be delay for SAR development if a generator verification standard is required. 3) There is risk associated with performing staged generation tests however, the SDT believes the benefits outweigh the risks. Exciter verification testing is essential for ensuring accurate dynamic simulations. To mitigate risk to the transmission system, the SDT recognizes that it is important to have testing personnel notify the Transmission Operator of scheduled tests, and interact as needed during the testing evolution.. System security must be maintained during the test. As example, system conditions may require the Transmission Operator to cancel planned testing. Also keep in mind verification requirements include alternatives to performing staged tests such as system performance monitoring under ambient conditions; which would be preferable to performing staged tests in some circumstances. Bench testing may be another viable option. A verification expert can evaluate available alternatives and assist with performing a situation specific risk/benefit assessment. 4) The SDT agrees with this recommendation and has incorporated the concept into Requirement R3 (Reference Requirement R1 in the revised standard). However, the SDT did not adopt the recommendation for R4 item 2 (Reference Requirement R2, Part 2.1 in the revised standard). To ensure consistency, it is important that the generator model data is always provided with the exciter model data even if it the data has not changed. The SDT does not believe this is a burdensome requirement given the benefit realized by ensuring necessary data is clearly communicated.		
AESO	Yes	The AESO agrees with the SRC ISO/RTO comments.
Response: Thank you for your comment. Please see the response to the comments provided by the SRC ISO/RTO.		
Duke Energy	Yes	Supplying the data itself is appropriate. Industry experience has shown that simply assuring the generator data in the model is the right data for the installed equipment is adequate for assuring the validity of the Generator Parameters, additional testing is not typically needed and any inappropriate data would show up in voltage bump test comparisons needed for AVR models validations. Also, R4.4, should say The GO shall provide the Compensation Function used on the unit (Droop, Reactive Line Drop or Resistive Line Drop) and the amount of compensation provided (% of generator voltage at rated MVA).
Response: Thank you for your comments. The SDT agrees inappropriate generator data would be identified during exciter verification. The SDT has revised Requirement R4.4 as follows: **Old Requirement R4.4, “**Reactive compensation settings (for example: reactive droop, line drop, differential compensation), if utilized.”		

Organization	Yes or No	Question 4 Comment
New Requirement R2, Part 2.1.5, "Compensation settings (such as droop, line drop, differential compensation), if used."		
Northeast Utilities	Yes	The entity specified in Question 4 does not agree with the entity specified in Requirement R4. As stated in our response to Question 1, we believe the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.
Response: Thank you for your comments. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
Reliant Energy	Yes	But to be I think it should be the GOP not the GO.
Response: Thank you for your comment. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
Hydro-Québec TransEnergie (HQT)	Yes	The entity specified in Question 4 does not agree with the entity specified in Requirement R4. As stated in our response to Question 1, we believe the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity to be the GO.
Response: Thank you for your comments. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
Independent Electricity System Operator	Yes	We agree with the approach of requiring the Generator Owner to supply the data listed. We also suggest that since this data is required within90 calendar days of completion of the excitation system model verification - the same condition for providing documentation demonstrating that the excitation system model's response matches the recorded response for a voltage excursion at the generator as stipulated in R8 - we suggest R8 be combined with R4. Note that "Generator Owner" instead of "Generator Operator" is used in this question. While we view this as a typo, as indicated in our comment under Q1 we think it is appropriate that the Generator Owners be held responsible for the majority of the requirements in this standard.
Response: Thank you for your comments. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1. The SDT agrees with the recommendation to combine Requirement R8 with R4 (reference Requirement R2, Part 2.1 in the revised standard).		

Organization	Yes or No	Question 4 Comment
American Transmission Company	Yes	It provides confirmation of whether the data being used to model the generator and the generator data used in the verification test are the same.
Response: Thank you for your comment.		
US Bureau of Reclamation	Yes	We agree the Generator Owner should provide the data and also be resposible for performing the model validation/verification.
Response: Thank you for your comment. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1.		
Kansas City Power & Light	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Pepco Holdings, Inc (PHI) - Affiliates	Yes	
FEUS	Yes	
Exelon Corporation	Yes	
Constellation Power Generation & Constellation Nuclear	Yes	
E.ON U.S.	Yes	
Wisconsin Public Service	Yes	
AWEA	Yes	
American Wind Energy	Yes	

Organization	Yes or No	Question 4 Comment
Association		
American Electric Power	Yes	
Arizona Public Service Co.	Yes	
Wisconsin Electric	Yes	
Manitoba Hydro	Yes	
Dynegy	Yes	
Southern California Edison	Yes	
ISO New England Inc.	Yes	
Xcel Energy	Yes	
Brazos Electric Power Cooperative	Yes	
Reliant Energy	Yes	

4.1 Do you believe that the SDT should consider expanding the scope, through a supplementary SAR, to include verification of generator data? If yes, please provide the scope of generation verification the SDT should consider, along with any data that would support the reliability benefits from expansion of the existing scope which could be included in a supplementary SAR.

Summary Consideration:

Most responders indicated that it is generally not necessary to separately verify the generator data in order to verify the excitation control system model. Most responders believed that a separate SAR would be required for a generator model verification standard. As such, the SDT decided not to expand the scope of this standard to include verification of generator model data.

Organization	Yes or No	Question 4.1 Comments and/or Supporting Data
Progress Energy, Inc.	No	To include generator data verfication beyond excitation system modeling data is a significant burden to the Generation Owner not supported by the benefits to be gained.
Response: Thank you for your comment**.** The SDT agrees separate testing is generally not required to develop a generator model. In order for simulation and measured results to match, the generator and excitation control system models must accurately represent the equipment.		
ISO New England Inc.	No	Manufacturer's estimates of generator characteristics appear to be generally accuracte and relatively easy to obtain.
Response: Thank you for your comment**.** The SDT agrees separate testing is generally not required to develop a generator model. In order for simulation and measured results to match, the generator and excitation control system models must accurately represent the equipment.		
Northeast Power Coordinating Council	No	Expanding the scope to include verification of generator data will not provide a significant improvement in the overall modeling of excitation systems.
Response: Thank you for your comment**.** The SDT agrees that separate verification of generator data is often unnecessary however, the SDT believes that a match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment.		
Dominion	No	MOD-024 and MOD-025 address a generator's real and reactive capability verification and MOD-026 addresses the excitation system verification. It seems desirable to have a MOD standard that address the verification of

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4.1 Comments and/or Supporting Data</th></tr>
<tr><td></td><td></td><td>generator data by the Generator Owner (not the Generator Operator). This can be handled by a new SAR since the scope change of the current SAR could delay the process. In scoping the verification of the generator dynamic data:a) If the existing generator dynamic model data is backed by documentation provided by the generator manufacturer or previous test(however old it is), no verification would be required. b) If there is no documentation (from manufacturer or previous test) supporting the existing generator dynamic model data, saturation, inertia & D-axis parameters (time constants and impedances) have to be verified at the minimum. If the measured D-axis parameters show reasonable agreement with the existing generator dynamic data, it is not required to verify the Q-axis parameters; otherwise the Q-axis parameters need to be verified as well.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT has corrected the noted error. The issue of whether the Generator Owner or Generator Operator is the responsible entity is addressed by Question 1. The SDT agrees that concerns regarding generator model verification should not be allowed to delay implementation of the MOD-026 proposed standard. The SDT also agrees that appropriate generator parameters are required to develop an accurate excitation system model. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. Further testing should not be necessary if a match is obtained between simulation and measured results, Further testing may be necessary to verify the parameters listed in your comment if a match is not obtained.</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>There are clearly benefits to having as much verified operational characteristic data as possible, however, as previously noted in response to question #2, the equipment risks associated with obtaining those benefits should be a consideration. Considering an aging generation infrastructure, the risk of obtaining parts for equipment damaged in the pursuit of modeling verification can be extremely costly in extended downtime and the availability of parts is also a concern. Again, it is recommended the SDT consider the removal or modification of requirements involving testing that place an unncessary risk of generator damage. As an example, allowing vendor simulations or other testing methods by the generator Vendor in a suitable testing environment to suffice for obtaining generator response characteristics.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT believes the testing required to verify the generator and excitation system models imposes minimal risk on equipment, with testing routinely finding maintenance issues that could cause equipment damage if uncorrected. The MOD-026 standard has been designed to allow testing experts to determine appropriate verification methods for the equipment that minimizes risk associated with aged equipment. This includes ambient monitoring which results in no additional risk to the unit beyond normal operation.</td></tr>
<tr><td>IRC Standards Review Committee</td><td>No</td><td>This standard should focus on the excitation system only. If the industry sees a need for such verification, the requirements could be added to another MOD standard or a separate standard be created through a separate SAR.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT agrees that if a generator verification standard is necessary, then it should be proposed in a separate SAR in</td></tr>
</table>

Organization	Yes or No	Question 4.1 Comments and/or Supporting Data
order to prevent implementation delays for this standard.		
Exelon Corporation	No	Verification of the generator data will be useful, but needs to be considered at a later date.
Response: Thank you for your comment**.** The SDT agrees that if a generator verification standard is necessary, then it should be proposed in a separate SAR in order to prevent implementation delays for this standard.		
Constellation Power Generation & Constellation Nuclear	No	Expanding the scope to include verification of generator data will not provide any significant improvement in the modeling of excitation systems.
Response: Thank you for your comment**.** The SDT agrees separate testing is generally not required to develop a generator model. In order for simulation and measured results to match, the generator and excitation control system models must accurately represent the equipment.		
Southern Company	No	As a general rule the industry has not demonstrated a need to validate OEM supplied generator data.
Response: Thank you for your comment. The SDT agrees that separate validation of Original Equipment Manufacturer supplied generator data is generally not required however, the SDT believes a match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment.		
E.ON U.S.	No	E.ON U.S. believes that entities have no incentive to use inaccurate data when conducting verifications studies. Strict data verification standards are in this instance an unproductive use of resources.
Response: Thank you for your comments. The SDT agrees that entities do not have incentive to use inaccurate data however experience indicates data representing generator and exciter models is often inaccurate, with simulation results predicting stable performance for situations where system performance was unstable. Experience has proven the need for model verification. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment.		
Wisconsin Public Service	No	The model generally in use to simulate generator dynamic responses is a hypothetical model based on fictitious parameters. For instance, the direct-axis and quadratual-axis impedances are calculated design values, and not a measurable physical quantity, as are the transient and subtransient time constances. The inertial constance involve the whole rotor and prime-mover assembly, and cannot be easily quantified.
Response: Thank you for your comments**.** Generator parameters such as inertia are verified by testing, including ambient monitoring. For example, the inertia can be calculated using the dimensions of the rotor and prime mover assembly. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment.		

Organization	Yes or No	Question 4.1 Comments and/or Supporting Data
Hydro-Québec TransEnergie (HQT)	No	Expanding the scope to include verification of generator data will not provide a significant improvement in the overall modeling of excitation systems. However, these data should be provided as part of an existing Standards or from another Standards if not already existing.
Response: Thank you for your comments**.** The SDT agrees separate verification of generator data is unnecessary however, the SDT believes that when a testing expert verifies the excitation system model data, the generator model data is also verified. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment.		
Consumers Energy Company	No	
Southwest Power Pool Generation Working Group	No	
SERC Dynamics Review Subcommittee (DRS)	No	
MRO NERC Standards Review Subcommittee	No	
FirstEnergy	No	
Pepco Holdings, Inc (PHI) - Affiliates	No	
Entergy Fossil Operations	No	
FEUS	No	
Luminant Power	No	
Cowlitz County PUD	No	
City of Garland, Garland Power &	No	

Organization	Yes or No	Question 4.1 Comments and/or Supporting Data
Light - GOP Registered Entity		
AWEA	No	
American Wind Energy Association	No	
Arizona Public Service Co.	No	
Wisconsin Electric	No	
Manitoba Hydro	No	
Dynegy	No	
Reliant Energy	No	
Southern California Edison	No	
Indiana Municipal Power Agency	No	
Reliant Energy	No	
Ameren	No	None
American Electric Power	Yes	Generator parameters are needed to support modeling. Later phases could pick-up unknowns identified by examining discrepancies between actual operation and modeling.
Response: Thank you for your comments**.** The SDT agrees that appropriate generator parameters are essential for developing an accurate excitation system model. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment.		
Northeast Utilities	Yes	Consider model verification for rotational inertia, which can have a significant effect on modelling.

Organization	Yes or No	Question 4.1 Comments and/or Supporting Data
Response: Thank you for your comment. The SDT agrees separate testing is generally not required to develop a generator model even though rotational inertia can have a significant effect. a match between simulation and measured results for the excitation system model is required to indicate that the generator (including the rotational inertia) and excitation control system models accurately represent the equipment.		
AESO	Yes	The exciter is only one component of the generator, testing all components (generator, exciter, PSS and governor/prime mover) is imperative so a complete picture of how the unit will react within the electrical system can be modeled. For the same reason units such as wind facilities and other types of generation that do not have an exciter must be modeled and verified.
Response: Thank you for your comments. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. The SDT agrees that in some circumstances it may not be necessary to perform further testing to establish appropriate models for the generator. The MOD-027 proposed standard will address modeling of the governor/prime mover. Generic models have recently been developed for wind facilities, which the SDT agrees additional work is needed to ensure appropriate models are established for wind facilities, solar facilities, etc. The standard has been modified to include verification requirements for these facilities.		
Duke Energy	Yes	Per the title, this is a standard applicable to the verification of excitation system models and the industry understands this to be different than the generator parameters. Requiring testing to specifically validate that generator data might require more than a bump test, which is currently thought to be adequate to address the issues currently in this standard. The generator reactances and time constants should not need verification as long as there is valid manufacturer supplied data and the generator has not been modified (rotor replacement, etc.) or condition has not degraded, such as the unit has been identified to have shorted rotor turns which would be expected to impact saturation curves and several of the reactance modeled. Additional testing might be appropriate when it is identified that a unit is operating with shorted turns, or if changes are made if a bump test cannot revalidate what is needed (such as a rotor replacement - do you need to verify saturation curves or when you remove a rotating exciter, do you need a load rejection test). NERC should consider establishing and documenting requirements for when model data validation should be re-verified and minimum tests needed for partial unit upgrades (e.g. what testing is required for a rotor replacement). Thus, it would seem a supplementary SAR to include generator parameter validation is needed. NERC should also consider developing a guide that provides input on these issues, especially if the responsibility is assigned to a GO/GOP without the technical background in models and validation. SERC developed a guide on this subject that could be leveraged for a NERC guide.
Response: Thank you for your comments. The SDT agrees separate verification of generator data is unnecessary however, the SDT believes that when a testing expert verifies the excitation system model data, the generator model data is also verified. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. Additional testing may be		

Organization	Yes or No	Question 4.1 Comments and/or Supporting Data
necessary if new data needs to be added to the generator model. The SDT agrees that the concept of a supplemental SAR should be discussed to ensure identified issues are included when performing unit upgrades.		
NERC Event Analysis & Information Exchange staff	Yes	It seems that having an overall generator testing standard in place on the dynamic parameters listed in MOD-013 would be a prerequisite for an excitation testing standard.
Response: Thank you for your comment. The SDT agrees that an accurate representation of the generator system is essential to obtain a match between simulated and measured results however, the SDT believes that a match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. If the results do not match, then further testing may be required to develop appropriate generator parameters. To prevent further delays with developing the MOD-026 standard, the SDT will not consider a generator verification standard as part of the exciter verification standard development process.		
Independent Electricity System Operator	Yes	We think that at a minimum, the generator's basic characteristics such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), voltage regulators, turbine-governor systems, etc. as stipulated in MOD-013 that support modeling for dynamic simulations should be verified. .A good excitation system model without a valid generator model will not provide the assurance that the simulation results are valid, which may hurt reliability.
Response: Thank you for your comments. The SDT agrees that appropriate dynamic models are needed for generators, exciters, PSS, and governors. The SDT believes that when testing personnel verify the excitation system model data, they also provide verification of the generator model data. a match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. The governor model is not verified with the excitation system model since it requires a frequency excursion. Verification of the governor model will be addressed by the MOD-027 standard. Experience indicates verification required by the MOD-026 standard often results in discovery of significant changes to the representation of the generator and exciter, suggesting that model verification provides significant reliability improvement.		
US Bureau of Reclamation	Yes	Yes, we believe other accurate dynamic models (e.g. generator model, governor model) are needed for valid computer simulations and should be required. Existing standards, MOD-012-0 Dynamics Data for Transmission System Modeling and Simulation and MOD-013-0, RRO Dynamics Data Requirements and Reporting Procedures (not FERC approved) already require each reliability region to determine comprehensive dynamics data requirements and Generator Owners to provide such modeling data. If these standards are being performed it is questionable what additional reliability concern is served by draft PRC-026-1.
Response: Thank you for your comments. The SDT agrees that appropriate dynamic models are needed for generators, exciters, PSS, and governors. The SDT believes that verification of the excitation system model data also provides verification of the generator model data. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. The governor model is not verified with the excitation system model since it requires a frequency excursion. Verification of the governor model will be addressed by		

Organization	Yes or No	Question 4.1 Comments and/or Supporting Data
the MOD-027 standard. The MOD-026 standard requires verification, while the MOD-012 standard simply requires that the data be provided. Experience indicates verification required by the MOD-026 standard often results in discovery of significant changes to the representation of the generator and exciter, suggesting that model verification provides significant reliability improvement.		
Xcel Energy	Yes	
American Transmission Company	Yes	

5. MOD-026 Requirement R8 requires the Generator Operator to provide documentation demonstrating that the provided model's response matches the recorded response. It does not specify criteria for evaluating the match. Requirement R8 assigns the task of evaluating the match to the Generator Operator. A peer review process for this documentation, detailed in Requirement R10(R1 in the second draft of the standard), gives other involved parties an avenue to provide input and voice any concerns.

Do you agree with the approach of the Generator Operator determining if the match is sufficient and the peer review process?

Summary Consideration:

The majority of industry agrees with allowing the generator entity to evaluate how accurately the recorded equipment response matches the model predicted response; and with the peer review process. Based on industry feedback received, the Generator Owner (as discussed in Question 1) is the entity responsible for model verification in the second draft of the standard.

Organization	Yes or No	Question 5 Comments
NERC Event Analysis & Information Exchange staff	No	The peer review process in R10 assumes that since the GOP operates the equipment, they are a technical authority on its modeling and behavior. Historically, that has been not necessarily correct, even of the owners of the equipment. Changes to excitation system models should be peer reviewed. However, a dispute resolution process would be needed for disagreements between the owners/operators and the peer team.
Response: Thank you for your comments. The SDT believes that the Generator Owner has the option of either developing in-house expertise, or entering into an agreement with a consultant, or entering into an agreement with its Transmission Planner. The SDT also believes that the Generator Owner, as owner of the model, has resolution authority for any model disagreement with the peer review team.		
Southwest Power Pool Generation Working Group	No	It is understood and agreed that many differing types of units and testing exist. With that thought in mind, it is felt the standard needs to provide some guidelines of how to perform the test and what type of test results are to be reported.
Response: Thank you for your comments. The SDT does not believe it is necessary to provide guidelines on how to perform the test or how to report results given established guidelines and procedures already exist within the industry including several available papers & publications on this issue. It is not practical to provide testing details in the standard that cover all types of excitation control system technologies. If an entity is not familiar with these testing methods and procedures, then the SDT recommends that they should develop in-house expertise (e.g. working with its Transmission Planner) or hire a consultant with expertise		

Organization	Yes or No	Question 5 Comments
testing generators.		
Northeast Power Coordinating Council	No	As stated in our response to Question 1, we believe that the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.
Response: Thank you for your comments. The SDT has assigned model verification responsibility to the Generator Owner in the next posting of the standard.		
Entergy Fossil Operations	No	This should be the Transmission planner's job. The GO or GOP does not use this data or the software or the expertise and may not be aware of disturbances on the system. The TP should compare this data and furnish it to the GO if there is an issue.
Response: Thank you for your comments. The SDT disagrees and believes that since the Generator Owner has physical access to the equipment and operates the equipment, it is the proper entity to be responsible for model testing and verification activities. If an entity is not familiar with these test methods and procedures or does not possess the necessary expertise, then the SDT recommends that the entity develop in-house expertise or hire a consultant who has generator testing expertise.		
IRC Standards Review Committee	No	As the facility owner, the Generator Owners should have the authority to confirm the accuracy of the model, which when supported by documentation, should suffice. A peer review is not necessary, and if "match" must be quantified, the industry may develop a set of criteria based on historical verification test data, and add this to the standard at a later stage.
Response: Thank you for your comments. The SDT agrees with your first comment. The SDT disagrees with the second comment that “peer review is not necessary”. The SDT believes peer review is an essential part of the model verification process irrespective of criteria or guidelines available from industry since peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided.		
FEUS	No	No, This allows for ambiguity in the interpretation of the standard by both the entity and the requlator.
Response: Thank you for your comments. The SDT considered ways to quantify a method for evaluating how well the equipment’s measured response matches the model’s predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process is necessary for ensuring quality. The SDT believes everyone involved in the peer review process has common motivation to develop an accurate excitation control system model.		
Exelon Corporation	No	Exelon feels that the standard should define the acceptance criteria. If the acceptance criteria is left up to the generator owners, then the TOs may have to deal with multiple acceptance criteria within a single region. At the same time, a single generator owner may have to work with multiple TOs, which will lead to inconsistency if the

Organization	Yes or No	Question 5 Comments
		definition of the acceptance criteria is left up to the TO.
Response: Thank you for your comments. The SDT has researched this concern and cannot find uniform guidelines or criteria available to industry for addressing/defining this issue. Therefore, the SDT believes the Generator Owner should use engineering judgment when addressing this issue.		
Consumers Energy Company	No	It is the Transmission Operator and the Transmission Planner's task to determine if the model matches. The Generator Operator is uniquely unsuited to monitor transmission lines and determine if the model works. If the Transmission Planner's model doesn't properly reflect reality, the Transmission Planner should be required to meet with the Generator Operator and discuss the issue. The Generator Operator should then be required to re-verify the data in question.
Response: Thank you for your comments. The SDT disagrees with the first comment that the Transmission Operator and Transmission Planner should be responsible for determining if the model is accurate. The SDT believes that since the Generator Owner owns and has physical access to the equipment, it is the proper entity to be responsible for model testing and verification activities. If an entity is not familiar with these test methods and procedures or does not possess the necessary expertise, then the SDT recommends that the entity develop in-house expertise or hire a consultant who has generator testing expertise. Regarding the second part of the comment, reference Requirement R2 in the revised standard concerning “model matching” and “verification”.		
City of Garland, Garland Power & Light - GOP Registered Entity	No	This should be the role of the Generator Owner (GO) - the GO has the data, the GO has the equipment, and the GO can schedule any required operational testing through the GOP.
Response: Thank you for your comments. The SDT agrees and has assigned this responsibility to the Generator Owner in the second draft of the standard.		
American Electric Power	No	AEP does not agree that the Generator Operator should not be responsible to provide documentation that the system model matches the recorded response. That responsibility should lie with the Generator Owner to review and decide how to have that analysis performed and to what extent documentation will be prepared to provide the required verification.
Response: Thank you for your comments. The SDT agrees and has assigned this responsibility to the Generator Owner in the second draft of the standard.		
Wisconsin Electric	No	The requirements in R8 and R9 are not clear to us. The term "recorded response" needs to be defined, and the term "voltage excursion" needs to be quantified. These requirements infer that the GOP already has some documentation of what a "correct" response looks like, which is not the case. The requirement to validate the exciter model by monitoring its response to a real or staged event is not a simple matter. For a staged event such as switching a line, the TO or TOP will need to be actively involved in the process, and should have some responsibility assigned to it in the standard. Likewise, if an ambient switching event is used to validate the model,

Organization	Yes or No	Question 5 Comments
		the TO/TOP would be the only entities in a position to know about it, since such operations may not be known by the GOP. In summary, this validation depends on shared responsibilities among the entities, and the requirements in this standard should properly reflect this.
Response: Thank you for your comments. The difference between Requirements R8 and R9 is that Requirement R9 requires the Generator Owner to make the documentation of predicted versus recorded response developed in R8 available to interested parties upon request. In the revised standard (reference Requirement R2 in the revised standard). The SDT believes that "recorded response" and "voltage excursions" are understood industry terms and there is not a need for further clarification of these terms. The SDT agrees that in order to validate the model using "staged testing" or "ambient monitoring", close coordination will be required between the Generator Owner and the TO/TP. Since the "Generator Owner" is the owner of this process, the Generator Owner has ultimate responsibility for testing and verifying the model. The SDT believes it is not practical to include a new requirement in the standard addressing shared model verification responsibilities. Also note that an "open circuit step in voltage" test is the most likely staged test that will be performed. This is a common test performed on a unit while it is at rated speed and voltage but not synchronized to the transmission system; and not a "staged test" by performing some sort of transmission system switching.		
Dynegy	No	See response to Item #1.
Response: Thank you for your comment. Please refer to the response provided to Dynegy's comment in Question 1.		
Northeast Utilities	No	As stated in our response to Question 1, we believe that the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.Agree that peer review by TP/PC is important for verifying the match.
Response: Thank you for your comments. The SDT agrees and has assigned this responsibility to the Generator Owner in the second draft of the standard.		
Reliant Energy	No	It should be the TP working with the GOP.
Response: Thank you for your comment. Requirements in the second draft of the standard define collaboration and peer review process language requiring the Transmission Planner to work with the generation entity.		
ISO New England Inc.	No	The generator should provide the data to Reliability Coordinators, Transmission Operators and Planning Coordinators for verification. Generator Owners should provide factory models for excitation systems to Reliability Coordinators, Transmission Operators and Planning Coordinators and these models should be verified with the field data.

Organization	Yes or No	Question 5 Comments
Response: Thank you for your comments. The SDT does not understand the intent of this comment. If the comment questions who should perform model verification process tasks, the SDT believes that the Generator Owner is the appropriate entity to verify the model. Please refer to Question 1 for additional explanation.		
Ameren	No	(1) Generator Operators and Generator Owners should be included in this standard. It is possible that all functions can not be performed by the Generator Operator. Therefore it would be prudent to include the Generator Owners within MOD-026-1. The Generator Operator or Generator Owner should verify the model but should not be responsible for the model.(2) No issues with peer-to peer review, as this would help drive what are necessary and sufficient conditions for matching the responses.(3) The functional model entity responsible for the model's verification has to be given the responsibility of demonstrating that the provided model's response matches the recorded response. The "goodness of fit" between the model response and the equipment response should be left to the generator owner but subject to Transmission Planner review ref. R10.
Response: Thank you for your comments. Regarding Comment #1: Based on the majority of industry comments and guidance from the FMWG, the second draft of the standard assigns responsibility to the Generator Owner. As mandated by Reliability Standard process, only one entity is assigned responsibility for excitation system model verification. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. The SDT agrees with comments #2 and #3 provided.		
AESO	No	The AESO agrees with the SRC ISO/RTO comments.
Response: Thank you for your comment. Please reference responses to SRC ISO/RTO comments.		
Hydro-Québec TransEnergie (HQT)	No	As stated in our response to Question 1, we believe that the Generator Owner is the correct entity to provide the data; not the Generator Operator. We agree with the approach subject to revising the responsible entity.
Response: Thank you for your comments. For the reasons stated in response to your comment in Question 1, the Generator Owner has been assigned responsibility for model verification in the second draft of the standard.		
Independent Electricity System	No	We have difficulty with the concept since the GOP's determination of a "match" can be subjective and subsequent peer review is time consuming and unnecessary if some matching criteria is developed up front. While we are not

Organization	Yes or No	Question 5 Comments
Operator		in a position to suggest what that criteria should be, we tend to think that a certain percentage of deviation in some output parameters may serve to provide this measure.Also, as indicated under Q4, we suggest R8 be combined with R4. It may be a moot point if some criteria are developed but if not, there are inconsistencies among R4, R8, R9 and R10 on the recipients of the documentation that the Generator Operator must provide and the feedback to be received. We suggest the SDT review the list of recipients, and if peer review is still required then the recipients/commenters should include Transmission Planners, Planning Coordinators, Transmission Operators and Reliability Coordinators since they all are users of the data and model.
Response: Thank you for your comments. The SDT has researched this concern and cannot find uniform guidelines or criteria available to industry for addressing/defining this issue. Therefore, the SDT believes the Generator Owner should use engineering judgment when addressing this issue. The SDT agrees with the recommendation to combine Requirement R8 with R4 (reference Requirement R2, Part 2.1 in the revised standard). The SDT will strive to ensure the proper functional model entities are included in the peer review process.		
Brazos Electric Power Cooperative	No	The Generator Owner should be responsible.
Response: Thank you for your comment. The SDT agrees and has assigned this responsibility to the Generator Owner in the second draft of the standard.		
US Bureau of Reclamation	No	Again we think the Generator Owner should be the responsible entity. This standard applies to only two entities, the Generator entity and the Transmission Planner; however actions by other entities, Reliability Coordinator and Transmission Operator, are required to accomplish the goals of the standard. The exact requirements of these entities should be described in the Standard.
Response: Thank you for your comments. The SDT has assigned responsibility of model verification to the Generator Owner in the second draft of the standard. Also, potential interactions with the Reliability Coordinator and the Transmission Planner are also specified in the draft standard.		
Reliant Energy	No	Peer review works well when performed by reasonable professional with the right motives. The only disagreement is that the Transmission Planner can arbitrarily reject the model and data without assuming any responsibility for the corrections or the cost.
Response: Thank you for your comments. The SDT believes that in a professional environment the peer review process will function properly given it is in the best interest of the Transmission Planner to resolve model issues with the Generator Owner in an expedient manner.		

Organization	Yes or No	Question 5 Comments
Constellation Power Generation & Constellation Nuclear	No	
SERC Dynamics Review Subcommittee (DRS)	Yes	The entity responsible for the model's verification has to be given the responsibility of demonstrating that the model's response matches the recorded response. The "goodness of fit" between the model response and the recorded response should be left to the generator owner but subject to Transmission Planner review ref. R10.
Response: Thank you for your comments. The SDT agrees with your comments.		
FirstEnergy	Yes	1. For many GOP's, a testing contractor with experience in model fitting and selection will need be hired to do the verification. 2. The team may want to add an additional requirement for the Transmission Planner to review and confirm acceptability of the Generator Operator's excitation system model verification documentation within 90 days of submittal. This would preceed the R10 requirement.
Response: Thank you for your comments. Regarding comment #1. If an entity is not familiar with these test methods and procedures or does not possess the necessary expertise, then the SDT recommends that the entity develop in-house expertise or hire a consultant who has generator testing expertise. Regarding comment #2. The SDT agrees. Reference Requirement R6.		
Manitoba Hydro	Yes	This should be done in consultation with planning/operating studies groups, since invariably these groups possess the necessary expertise and are in a better position to adjust/modify the model.
Response: Thank you for your comments. The SDT notes that existing arrangements or new arrangements for model verification can be established by the Generator Owner. However, even if the Generator Owner obtains assistance from its Transmission Planner or another entity (such as a consultant) for any step of the model verification process, the Generator Owner maintains responsibility for model verification as specified in the draft standard. It should also be noted that while the Transmission Planner may have expertise running the dynamic stability software, most Transmission Planners do not possess expertise with reviewing generator model dynamic data and modifying the model.		
Progress Energy, Inc.	Yes	The functional model entity responsible for the model's verification has to be given the responsibility of demonstrating that the provided model's response matches the recorded response. The "goodness of fit" between the model response and the equipment response should be left to the generator owner but subject to Transmission Planner review ref. R10.
Response: Thank you for your comments. The SDT agrees with your comments.		

Organization	Yes or No	Question 5 Comments
Duke Energy	Yes	We agree the standard should not set criteria for evaluating the match, but industry guidance on acceptable criteria would be helpful.
Response: Thank you for your comment. Since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process is necessary for ensuring quality. The SDT believes everyone involved in the peer review process has common motivation to develop an accurate excitation control system model. Therefore the SDT does not recommend establishing quantitative criteria for evaluating the match.		
Dominion	Yes	
Kansas City Power & Light	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Pepco Holdings, Inc (PHI) – Affiliates	Yes	
Luminant Power	Yes	
Southern Company	Yes	
Cowlitz County PUD	Yes	
E.ON U.S.	Yes	
Wisconsin Public Service	Yes	
AWEA	Yes	
American Wind Energy Association	Yes	
Arizona Public Service Co.	Yes	

Organization	Yes or No	Question 5 Comments
Southern California Edison	Yes	
Indiana Municipal Power Agency	Yes	
CenterPoint Energy	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	

6. The team purposely provided minimal specificity regarding the mechanics of performing excitation system verification and the development of the documentation showing that the provided model response matches the recorded response. The team felt it was impractical to provide verification details in a mandatory Reliability Standard that needs to be applicable to all of the existing and future technologies.

Do you agree with this approach? If no, please elaborate on the additional specificity that you feel is appropriate with specific examples and/or proposed Reliability Standard language.

Summary Consideration:

The majority of industry responders agree only minimal verification details should be provided in the standard. Industry response indicates additional modification to the second posting of the standard is not required for this comment.

Organization	Yes or No	Question 6 Comments
Southwest Power Pool Generation Working Group	No	It is understood and agreed that many differing types of units and testing exist. With that thought in mind, it is felt the standard needs to provide some guidelines on how to perform the test and what type of test results are to be reported.
Response: Thank you for your comments. The majority of industry agrees with the SDT that it is impractical to provide sufficient technical details that would apply to all types of technology.		
Entergy Fossil Operations	No	I do agree with not making the standard too large, but somewhere the GVSDT needs to provide this detailed data or training to the GO/GOP. You are requiring them to provide things that they do not have expertise in and this will lead to problems with getting this done correctly and for a reasonable price. I'm sure the contractors that do with work see a big opportunity to make money on this.
Response: Thank you for your comments. The majority of industry agrees with the SDT that minimal technical specificity is appropriate for this standard.		
FEUS	No	This leaves ambiguity in the standard that can be to misinterpretation by the entity or the agency. Some guidelines should be provided for standardization to avoid confusion.
Response: Thank you for your comments. The SDT believes it is impractical to add sufficient technical details that would apply to all types of technology, that doing so would be counter-productive and cumbersome, and that it is best to let the technical experts determine this information.		

Organization	Yes or No	Question 6 Comments
E.ON U.S.	No	While E.ON U.S. appreciates that the concern over requirements applicable to both existing and future technologies, the lack of any specific guidance on process and verification methodologies invites differing interpretations of the standard. This lack of specificity makes compliance problematic.
Response: Thank you for your comments. The SDT believes that the majority of industry agrees that if the equipment recorded response matches the models predicted response, verification of the model has been achieved. Also, the draft standard includes a peer review process intended to ensure verification process quality. The SDT has made substantial effort to ensure the Requirements can be clearly evaluated from a compliance perspective.		
ISO New England Inc.	No	This may lead to "weak" submittals from certain entities.
Response: Thank you for your comments. The SDT believes the interactions and checks listed in the Requirements of the draft standard along with the peer review process will mitigate model verification quality concerns.		
American Transmission Company	No	Standard testing procedures should be provided as a minimum with the caveate "that the testing procedures include but are not limited to these procedures" to cover future technologies. An example would be a step response test for the exciter; swept frequecy (0.1 t0 10 Hz) response test for a PSS.
Response: Thank you for your comments. The majority of industry responses indicate the technical details should be left to the experts performing testing and model verification.		
Northeast Power Coordinating Council	Yes	Reliability Standards should focus on what is required and not how to meet the requirement. Further, it would be impractical to specify verification details universally applicable to all situations. The peer review process provides appropriate safeguards to ensure that appropriate methods are used for verification.
Response: The SDT thanks you for your comment.		
SERC Dynamics Review Subcommittee (DRS)	Yes	We agree with the SDT approach of not writing this standard like a technology specific procedural manual. The development of verification Requirements stating "what is required" and leaving the technical details up to the personnel performing the verification will result in improved dynamic models while affording sufficient technical latitude.
Response: The SDT thanks you for your comment.		
FirstEnergy	Yes	While we agree with the approach of staying away from being too prescriptive, it may add guidance if the term

Organization	Yes or No	Question 6 Comments
		"verify" (i.e. in R1) was clarified. We ask the team to consider adding "such as operational tracking or testing" after verify.
Response: Thank you for your comments. Language of Requirement R8 has been added to the list of items required for model verification (reference Requirement R2, Part 2.1). This includes a reference that either a test or ambient monitoring is an acceptable alternative to capture the actual response of the equipment.		
Consumers Energy Company	Yes	Providing minimal specificity allows many approaches to meet the requirements. This accommodates the many present and future excitation technologies and monitoring techniques.
Response: The SDT appreciates your response.		
Wisconsin Public Service	Yes	I agree with the methodology of the SDT to leave the test methods required under R4 out of the standard. It is a good philosophy to not limit future advancements in testing because the standard specifially calls for a step voltage test or UEL / OEL bumps. I think the SDT should consider this methodology in future drafts as applicable.
Response: The SDT appreciates your response.		
American Electric Power	Yes	We are agreeable since there are different kinds of excitation systems.
Response: The SDT appreciates your response.		
Progress Energy, Inc.	Yes	We agree with the SDT approach of not developing this standard like a technology specific procedural manual. The development of verification Requirements stating "what is required" and leaving the technical details up to the personnel performing the verification will result in improved dynamic models while affording sufficient technical latitude.
Response: The SDT appreciates your response.		
Reliant Energy	Yes	I susgest that the SDT consider a white paper expounding how the verification can be performed.
Response: Thank you for your comments. The SDT believes that there are many technical references available which document verification processes that have been successfully utilized. Please refer to the References section of the draft standard.		

Organization	Yes or No	Question 6 Comments
Ameren	Yes	We agree with the SDT approach of not developing this standard like a technology specific procedural manual. The development of verification Requirements stating "what is required" and leaving the technical details up to the personnel performing the verification will result in improved dynamic models while affording sufficient technical latitude.
Response: The SDT appreciates your response.		
AESO	Yes	The AESO agrees with the SRC ISO/RTO.
Response: Thank you for your comment. Please see the response to the SRC ISO/RTO comment referenced.		
Duke Energy	Yes	We agree, but industry guidance on acceptable criteria would be helpful.
Response: Thank you for your comment. See the SDT response to this same issue under Question 6.		
Hydro-Québec TransEnergie (HQT)	Yes	Reliability Standards should focus on what is required and not how to meeet the requirement. Further, it would be impractical to specify verification details universally applicable to all situations. The peer review process provides appropriate safeguards to ensure that appropriate methods are used for verification. As an alternative, a technical white paper could be developped for reference.
Response: Thank you for your comments. The SDT did not develop a white paper because many excellent subject matter references already exist. Please refer to the Reference section of the draft standard.		
Independent Electricity System Operator	Yes	The SAR could be expanded by making it more clear that it applied not only to the excitation systems on conventional synchronous generation units but also to the equipment that performs this role on non-conventional facilities such as wind-farm voltage management systems.
Response: Thank you for your comments. The Applicability section MVA thresholds provided in the first posting of the MOD-026 standard omitted wind powered units because wind unit are not rated greater than 20 MVA. There is an increasing number of wind farms with significantly larger aggregate MVA and as such, their impact on the reliability of the Bulk Electric System cannot be ignored; otherwise a reliability gap would exist. The SDT discussed the possibility of requiring verification of dynamic models that represent the aggregate of numerous small units and any necessary auxiliary equipment required of the technology. This could include plant dynamic voltage control and reactive support of all the units and auxiliary equipment (such as individual WTG response, plant-wide volt/var controller response, and response from separate volt/var regulation devices contained in the plant such as SVC/STATCOM/Synchronous Condenser) contained in any technology generation plant, including a wind farm (plant), that exceeds the appropriate aggregate nameplate MVA threshold. There are dynamic models that adequately replicate wind unit performance for some wind units today however, there are many existing wind units for which there are not publicly available models		

Organization	Yes or No	Question 6 Comments
supplied by the Original Equipment Manufacturer. Generic wind models (i.e., type I, II, III and IV) are in various stages of development. Also, there are ongoing efforts involving Regional Entities and manufactures to close any large gaps that may exist in current generic models. Given the timeframe expected to lapse while awaiting standard approval by FERC, it is expected that generic wind farm (plant) models will sufficiently mature for establishing boundary conditions in Bulk System Studies. To mitigate this reliability gap, the Applicability section will be expanded in the second posting of the standard to include a significant MVA percentage of generation regardless of technology.		
NERC Event Analysis & Information Exchange staff	Yes	
Dominion	Yes	
Kansas City Power & Light	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Pepco Holdings, Inc (PHI) - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Luminant Power	Yes	
Exelon Corporation	Yes	
Constellation Power Generation & Constellation Nuclear	Yes	
Southern Company	Yes	
Cowlitz County PUD	Yes	
City of Garland, Garland Power & Light - GOP Registered Entity	Yes	

Organization	Yes or No	Question 6 Comments
AWEA	Yes	
American Wind Energy Association	Yes	
Arizona Public Service Co.	Yes	
Wisconsin Electric	Yes	
Manitoba Hydro	Yes	
Dynegy	Yes	
Northeast Utilities	Yes	
Southern California Edison	Yes	
Indiana Municipal Power Agency	Yes	
CenterPoint Energy	Yes	
Xcel Energy	Yes	
Brazos Electric Power Cooperative	Yes	
US Bureau of Reclamation	Yes	
Reliant Energy	Yes	

7. The SDT believes that this standard should not be applicable to low capacity factor units. The SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already accurately replicate actual equipment performance. By definition, low capacity factor units are expected to rarely be on-line, and even when they are, they would constitute a small portion of the interconnected MVA. As such, the SDT is of the opinion that verified excitation models for these units would not result in a substantial increase in Bulk Electric System reliability. Do you agree with this approach and the proposed 5% capacity factor?

Summary Consideration:

The majority of industry responders supported the 5% capacity factor criteria. In response to Industry comments for Question 9, the SDT has revised the standard to include a new Requirement that allows Planning Coordinators to specify, with technical justification, additional units to provide corrected model data or verify their excitation control system models. The SDT believes that this new Requirement will address the concerns expressed by several Industry responders.

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
NERC Event Analysis & Information Exchange staff	No (disagree with approach)	Units with a low capacity factor may well still be frequently needed, albeit for short but crucial periods, to support the system during peak load. Further, they may often be used in shoulder periods when primary resources are out on maintenance.	

Response: Thank you for your comments. The reason for choosing a 5% capacity factor as a threshold for exemption in conjunction with the proposed MVA-based exemption is by SDT collective experience. The increase in excitation control system model verification is expected to result in improved accuracy of stability based security assessments. The SDT does not believe un-verified data is necessarily inaccurate or that the overall stability of the system is sensitive to that data. The excitation information from the generating units with a 5% capacity factor or less, as provided per standards MOD-012 and MOD-013, is included in the models used to analyze the system under various conditions. Even if these low capacity factor generating units are verified, the accuracy of the simulation is not guaranteed because there are other significant assumptions involved in simulation results, such as load models. As such, the verified models do not provide absolute accuracy under operating conditions other than those conditions for which verification is performed.

Additionally, the SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2.

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
IRC Standards Review Committee	No (disagree with approach)	a. The Term Capacity Factor is capitalized but this term is not defined. Suggest to use lower case, or define it.b. Capacity factor reflects a generating unit's real power generation frequency and duration, but does not provide the assurance that when the generator is on line, it's excitation system has been verified such that its model is accurately represented in simulations. There are also sizable "mothballed" units that, due to various reasons, were put off line for a long period but return to service when the need for capacity so dictates. Not having their data verified based on a low capacity factor and on the assumption that they constitute a small portion of the interconnection MVA may leave room for unreliability. Moreover, having to track a unit's capacity factor for the past 5 years to determine the need for verification is an unnecessary administrative burden.	
Response: Thank you for your comments. The reason for choosing a 5% capacity factor as a threshold for exemption in conjunction with the proposed MVA-based exemption is by SDT collective experience. The increase in excitation control system model verification is expected to result in improved accuracy of stability based security assessments. The SDT does not believe un-verified data is necessarily inaccurate or that the overall stability of the system is sensitive to that data. The excitation information from the generating units with a 5% capacity factor or less, as provided per standards MOD-012 and MOD-013, is included in the models used to analyze the system under various conditions. Even if these low capacity factor generating units are verified, the accuracy of the simulation is not guaranteed because there are other significant assumptions involved in simulation results, such as load models. As such, the verified models do not provide absolute accuracy under operating conditions other than those conditions for which verification is performed. Additionally, the SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2.			
SERC Dynamics Review Subcommittee (DRS)	No (disagree with approach)	The 5% capacity factor is an inappropriate basis for an exemption criteria since it would allow significant blocks of generation (i.e. plants of several hundred MW) to be exempt. Units in this class of generation may have a significant impact on the stability of nearby generating units or may have stability issues that need to be understood via valid studies. Examples would be plants with multiple combustion turbine units (particularly simple cycle oil burners) that are rarely generating. However, when they are generating (i.e. during peak system	Based on the above discussion, the 5% capacity factor exemption should only be allowed when it would significantly impact the results of stability studies. Allowing the Transmission Planner to make this judgement is most appropriate since A) this entity is in the best position to make the determination of the impact on stability and B) this entity is responsible (via TPL standards) for ensuring the stability of the grid and connected

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
		load times), the grid may be already be stressed and operating with a reduced stability margin.The possibility also exists that while the exempted generation may have a historical capacity factor of less than 5%, this could quickly change due to unanticipated system conditions or the extended unavailability of other generation (due to severe damage for example). Therefore, the subject generating units could generate for a significant length of time without the benefit of having been properly analyzed by the Transmission Planning organization. The average over the last three calendar years methodology further contributes to this possibility, introducing a time lag in the process.	generating units.In lieu of the blanket 5% exemption, the following is proposed.1. Delete and with an average Capacity Factor of greater than 5% over the last three calendar years in all places in 4.1.1.1, 4.1.1.2 and 4.1.1.32. Add a new section under Applicabilty 4.1.1.4 stating ?Generating facilities with capacity factors less than 5% over the last three calendar years may be exempted with written concurrence from the applicable Transmission Planning Authority. The written concurrence provided by the Transmission Planning Authority shall include the basis for any such exemptions. alternative to (2.) could be the reponse to Q9 below.
Response: Thank you for your comments. Each registered generating unit reports excitation control system model information per standards MOD-012-1 and MOD-013-1, which means the unit excitation control system model is provided to the Transmission Planners. Because of the requirements in standards MOD-012 and MOD-013, the SDT believes that units with excitation control system models that have not been verified do not necessarily lead to inaccurate results or that the overall stability of the system is sensitive to “unverified” data. The validity of simulation results depends upon many assumptions such as load and other system models. At the end of every 10 year periodicity window, if a generating unit exceeds the 5% capacity factor, it must be tested within the next year if the unit has not been tested within the previous 10 year period. This testing timeframe is similar to the effective date timeframe specified in the standard. Additionally, the SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2. The SDT believes that defining a process where additional units could be identified for verification was a reasonable approach as opposed to defining a process where units with low capacity factor must apply for an exemption.			
Consumers Energy Company	No (disagree with approach)	We disagree with the approach. Some systems have very large peaking units which arguably are more likely to be in service on days when the BES would be challenged. Thus, modeling data should be collected for these units and model cases run including these data. Additionally, the requirement should only apply to peaking units which meet the applicability criteria (i.e. Capacity factor greater than 5% for the last 3 years and greater than the MVA indicated in 4.0)	
Response: Thank you for your comments. Each registered generating unit reports excitation model information per standards MOD-012 and MOD-013 and thus will be			

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
included in stability assessments performed with the model information included in the dynamics database. Also, modeling excitation control systems is most important for stability assessments, for which the most limiting scenario is almost always off peak conditions. Additionally, for the case where large units are exempt by size, interconnection voltage, or capacity factor, the SDT is proposing a new requirement that allows the Transmission Planner or the Planning Coordinator to identify additional generating units beyond the criteria established by section 4.2 that are needed for reliability.			
Wisconsin Public Service	No (disagree with approach)	Threshold should be set around 20% to remove the requirements from those operators that may have a large fleet of small CT's that operate only in minimal peakng mode, but would qualify under the multiple units on the same site provision. These units have minimal impact on the dynamic model.	
Response: Thank you for your comments. The SDT believes that the 5% Capacity Factor threshold functions to establish a balance between verifying modeling information for units that play an important role in the reliability of the BES and units that report information which is not verified because they are seldom online and have a relatively diminished reliability role. Also, note that the draft standard MOD-026 – Attachment 1 “Excitation Control System Model Verification Periodicity” provides conditions where the verification of one unit’s excitation control system model verification will satisfy multiple units.			
American Electric Power	No (disagree with approach)	Seldom run units could end up being run at peak times in areas that may be stability limited. Applicability should be driven by need for verification which historically, has been tied to stability performance and constraints.	
Response: Thank you for your comments. The SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2.			
Progress Energy, Inc.	No (disagree with approach)	The 5% capacity factor is an inappropriate basis for an exemption since it would allow significant blocks of generation (i.e. plants of several hundred MW) to be exempt. Such amounts of generation may have a significant impact on the stability of nearby generating units or such units may themselves have stability issues that need to be understood via valid studies. Examples would be plants with multiple combustion turbine units (particularly simple cycle oil burners) that are rarely run. However, when they are run (i.e. during peak system load times), the grid may be already be stressed and operating with reduced stability margin.The possibility also exists that while the exempted generation may have a capacity factor of less than	

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
		5%, this could quickly change due to unanticipated system conditions or the extended unavailability of other generation (due to severe damage for example). Therefore, the subject generating units could end up being run for a significant length of time without the benefit of having been properly analyzed by the Transmission Planning organization. The average over the last three calendar years methodology further contributes to this possibility, introducing a time lag in the process.Based on the above discussion, the 5% capacity factor exemption should only be allowed when it would not be expected to significantly impact the results of stability studies. Allowing the Transmission Planner to make this judgement is most appropriate since A) that organization is in the best position to make the determination of the impact on stability and B) that organization is responsible (via TPL standards) for ensuring the stability of the grid and connected generating units.In lieu of the blanket 5% exemption, the following is proposed.1. Delete and with an average Capacity Factor of greater than 5% over the last three calendar years in all places in 4.1.1.1, 4.1.1.2 and 4.1.1.32. Add new Applicabilty 4.1.1.4 stating Generating facilities with capacity factors less than 5% over the last three calendar years may be exempted with written concurrence from the applicable Transmission Planning Authority. The written concurrence provided by the Transmission Planning Authority shall include the basis for any such exemptions. alternative to (2.) could be the reponse to Q9 below.	

Response: Thank you for your comments. The reason for choosing a 5% capacity factor threshold for exemption is similar to those for MVA-based exemption. This is to strike a balance between the costs and benefits. Because the excitation data of a unit has not been verified does not imply that the data is necessarily inaccurate or that the overall stability of the system is sensitive to that data. While the scenario contemplated in the comment is realistic, the SDT does not believe that the reliability of an entire interconnection will be significantly impacted by these isolated incidences. The validity of simulation results depends upon many assumptions, such as load and other system models. Even if all excitation system models were based on testing it would not guarantee absolute accuracy. Based upon the majority of responses received from the industry the SDT believes that the 5% exemption threshold is appropriate.

Additionally, the SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2. The SDT believes felt that defining a process where additional

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
units could be identified for verification was a reasonable approach as opposed to defining a process where units with low capacity factor must apply for an exemption			
Independent Electricity System Operator	No (disagree with approach)	a. The Term Capacity Factor is capitalized but this term is not defined. Suggest to use lower case, or define it.b. Capacity factor reflects a generating unit's real power generation frequency and duration, but does not provide the assurance that when the generator is on line, it's excitation system has been modeled accurately such that its expected performance matches simulation results. There are generating units that are often on line but do not generate at high capacity since they provide ancillary services including operating reserve and hence tend to have a low capacity factor. There are also sizable "mothballed" units or the entire plant of multiple sizable units that, due to various reasons, were put off line for a long period but return to service when the need for capacity so dictates. Not having their data verified based on a low capacity factor and on the assumption that they constitute a small portion of the interconnection MVA may leave room for unreliability. Further, low capacity factor is a historical value which may not be a good indicator of the future. If and when these low-capacity generators are put to high capacity usage, and particularly when the system is being stressed, the non-verified excitation systems can give rise to unpredictable system performance.Moreover, having to track a unit's capacity factor for the past 5 years to determine the need for verification is an unnecessary administrative burden.	
Response: Thank you for your comments. The term “capacity factor” is written lower case in the second draft of the standard. Units with a 5% or less capacity factor average over the last three years have relatively small likelihood of impacting the reliability of the BES. If the three-year average capacity factor of these units increases above 5%, then the unit will be required to have its excitation information verified. Generally, the tracking of a unit’s capacity factor is performed yearly by the Generator Owner due to reporting requirements for environmental regulations which means this information is generally already calculated and available. Additionally, the SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2.			

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
ISO New England Inc.	No (disagree with approach)	These low capacity factor units may be critical during peak conditions and are almost certain to be older units that have the least accurate factory excitation system models. It is felt that having accurate models for these older units is required. Generators under 100 MVA make up about 15% of capacity in New England. Excluding low capacity factor large units may exclude more than 20% of the generators from model verification.	
Response: Thank you for your comments. The SDT intended to write section 4.2 so that it applied to eighty percent of the generating units in each interconnection region. The SDT has revised the draft standard to allow Planning Coordinators to identify additional units for verification beyond section 4.2.			
Ameren	No (disagree with approach)	(1) Some systems have very large peaking units which arguably are more likely to be in service on days when the BES would be challenged. Thus, modeling data should be collected for these units and model cases run including these data.(2) The 5% capacity factor is an inappropriate basis for an exemption since it would allow significant blocks of generation (i.e. plants of several hundred MW) to be exempt. Such amounts of generation may have a significant impact on the stability of nearby generating units or such units may themselves have stability issues that need to be understood via valid studies. Examples would be plants with multiple combustion turbine units (particularly simple cycle oil burners) that are rarely run. However, when they are run (i.e. during peak system load times), the grid may be already be stressed and operating with reduced stability margin.(3) The possibility also exists that while the exempted generation may have a capacity factor of less than 5%, this could quickly change due to unanticipated system conditions or the extended unavailability of other generation (due to severe damage for example). Therefore, the subject generating units could end up being run for a significant length of time without the benefit of having been properly analyzed by the Transmission Planning organization. The average over the last three calendar years methodology further contributes to this	

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
		possibility, introducing a time lag in the process.Based on the above discussion, the 5% capacity factor exemption should only be allowed when it would not be expected to significantly impact the results of stability studies. Allowing the Transmission Planner to make this judgement is most appropriate since A) that organization is in the best position to make the determination of the impact on stability and B) that organization is responsible (via TPL standards) for ensuring the stability of the grid and connected generating units.(4) In lieu of the blanket 5% exemption, the following is proposed.(a) Delete and with an average Capacity Factor of greater than 5% over the last three calendar years? in all places in 4.1.1.1, 4.1.1.2 and 4.1.1.3(b)Add new Applicabilty 4.1.1.4 stating ?Generating facilities with capacity factors less than 5% over the last three calendar years may be exempted with written concurrence from the applicable Transmission Planning Authority. The written concurrence provided by the Transmission Planning Authority shall include the basis for any such exemptions. (5) alternative to (b) could be the reponse to Q9 below.	
Response: Thank you for your comments. The excitation system modeling data for all registered generating units is collected per standards MOD-012-1 and MOD-013-1 and used in models by Transmission Planners. The SDT is proposing a change to the standard to allow Transmission Planners or Planning Coordinators to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2. The 5% or less average capacity factor over the last three years does not force Generator Operators to spend money on testing of units that do not contribute to the reliability of the BES. At the end of every 10 year periodicity period, if a generating unit exceeds the 5% capacity factor, it must be tested within the next year if the unit has not been tested within the previous 10 year period. This testing timeframe is similar to the effective date timeframe specified in the standard.			
AESO	No (disagree with approach)	The AESO agrees with the SRC ISO/RTO comments.	
Response: Thank you for your comments. Please see the response to the entity comment which was referenced.			
Duke Energy	No (disagree with approach)	Regarding Section 4 Applicability, drop the reference to Capacity Factor of 5% over the past 3 years. This makes no sense, because for a variety of reasons the unit's capacity factor in the very next year may be significantly higher, and having an	

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
		accurate assessment of the unit's performance would be important.The units with low capacity factor would likely be on line during a peak load period when the system is most stressed and stability issues are most likely. Also, these units could be relevant to sensitivity studies. The larger units should have a model. Additionally, MMWG requires models for all units whether they are on or off in the case. Each one must have a model if the modeling criteria is satisfied. If the unit is a reasonable size and connected to the BES like others, we don't see how you can exclude testing.	
Response: Thank you for your comments.. The reason for choosing a 5% capacity factor threshold for exemption is similar to those for MVA-based exemption. This is to strike a balance between the costs and benefits. Because the excitation data of a unit has not been verified does not imply that the data is necessarily inaccurate or that the overall stability of the system is sensitive to that data. While the scenario contemplated in the comment is realistic, the SDT does not believe that the reliability of an entire interconnection will be significantly impacted by these isolated incidences. The validity of simulation results depends upon many assumptions, such as load and other system models. Even if all excitation system models were based on testing it would not guarantee absolute accuracy. Based upon the majority of responses received from the industry the SDT believes that the 5% exemption threshold is appropriate. Additionally, the SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2.			
US Bureau of Reclamation	No (disagree with approach)	Capacity Factor (capitalized) is not defined in the standard nor is it defined in the NERC Glossary; we think we know what it means but if the term is used in the standard it should be defined. However we believe Capacity Factor, should not be used to exempt generators. Those times when generators of low Capacity Factor are in operation will most likely be those times when the power system is most stressed and the performance of the machines should be modeled in system studies.	
Response: Thank you for your comments. The use of the term "capacity factor" is written lower case in the second draft of the standard. It should be noted that infrequently operated units will still report unverified excitation information per standards MOD-012 and MOD-013 and the exciter information will be modeled in system studies.			

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
Pepco Holdings, Inc (PHI) - Affiliates	Yes agree with the approach. But use another capacity factor (include supporting data):		PHI does not see a substantial difference in reliablity if the capacity factor is increased to 10%
Response: Thank you for your comments. The SDT believes the majority of industry supports the 5% capacity factor threshold to establish a balance between verifying modeling information for units that play an important role in the reliability of the BES and units that report information which is not verified due to relatively diminished role in reliability because they are seldom online.			
Constellation Power Generation & Constellation Nuclear	Yes agree with the approach. But use another capacity factor (include supporting data):		
Response: Thank you for your comments. Unfortunately, since another capacity factor proposal was not included, the SDT cannot make a specific reply. However, the SDT believes that industry supports the assertion that the 5% capacity factor threshold to establish the balance between verifying modeling information for units that play an important role in the reliability of the BES, and units that report information which is not verified due to having a relatively diminished role in reliability because they are seldom online.			
City of Garland, Garland Power & Light - GOP Registered Entity	Yes agree with the approach. But use another capacity factor (include supporting data):	Not sure which box to comment in: Strongly agree with your approach & reasons but believe that 10% should be the exemption level	Not sure which box to comment in: Strongly agree with your approach & reasons but believe that 10% should be the exemption level
Response: Thank you for your comments. The SDT appreciates your comments. The SDT believes that the majority of industry supports the assertion that the 5% capacity factor threshold to establish the balance between verifying modeling information for units that play an important role in the reliability of the BES, and units that report information which is not verified due to having a relatively diminished role in reliability because they are seldom online.			
Reliant Energy	Yes agree with the approach. But use another capacity factor (include	Capacity factor should be raised to 15%.	

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
	supporting data):		
Response: Thank you for your comments.. The SDT believes that the 5% capacity factor threshold to establish the balance between verifying modeling information for units that play an important role in the reliability of the BES, and units that report information which is not verified due to having a relatively diminished role in reliability because they are seldom online.			
Northeast Power Coordinating Council	Yes agree with approach and the 5% capacity factor	We agree with this approach to exclude units with low capacity factors provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. Cases exist where large generating units with low capacity factors are operated only during the most stressed operating conditions. In such cases accurate modeling of these units may be critical to reliable operation of the bulk electric system.	
Response: Thank you for your comments. The SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2.			
Southern Company	Yes agree with approach and the 5% capacity factor		The idea that this standard should not be applicable to low capacity factor seems perferable. However, 5% capacity factor may be too high. For instance, there are 8760 hours in a year. A 5% capacity factor could mean a unit running its at nameplate MW for 438 hours. Or, it could mean more than 438 hours if the unit is not running at its nameplate all the time when running.For Southern Company Generation, the current criteria would result in the standard applying to at least 80% of our generation capacity.
Response: Thank you for your comments.. The SDT believes industry supports the 5% capacity factor threshold to establish a balance between verifying modeling information for units that play an important role in the reliability of the BES and units that report information which is not verified due to having a relatively diminished role in reliability because they are seldom online. Additionally, the SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional			

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
generating units that are critical for reliability beyond the applicability criteria established by section 4.2. The SDT believes that defining a process where additional units could be identified for verification was a reasonable approach as opposed to defining a process where units with low capacity factor must apply for an exemption.			
Manitoba Hydro	Yes agree with approach and the 5% capacity factor	Low capacity factor units such as wind turbines which could be part of a large MVA rated farm, should be in a separate category.	
Response: Thank you for your comment. The Applicability section MVA thresholds provided in the first posting of the MOD-026 standard omitted wind powered units because wind unit are not rated greater than 20 MVA. There is an increasing number of wind farms with significantly larger aggregate MVA and as such, their impact on the reliability of the Bulk Electric System cannot be ignored; otherwise a reliability gap would exist. The SDT discussed the possibility of requiring verification of dynamic models that represent the aggregate of numerous small units and any necessary auxiliary equipment required of the technology. This could include plant dynamic voltage control and reactive support of all the units and auxiliary equipment (such as individual WTG response, plant-wide volt/var controller response, and response from separate volt/var regulation devices contained in the plant such as SVC/STATCOM/Synchronous Condenser) contained in any technology generation plant, including a wind farm (plant), that exceeds the appropriate aggregate nameplate MVA threshold. There are dynamic models that adequately replicate wind unit performance for some wind units today however, there are many existing wind units for which there are not publicly available models supplied by the Original Equipment Manufacturer. Generic wind models (i.e., type I, II, III and IV) are in various stages of development. Also, there are ongoing efforts involving Regional Entities and manufactures to close any large gaps that may exist in current generic models. Given the timeframe expected to lapse while awaiting standard approval by FERC, it is expected that generic wind farm (plant) models will sufficiently mature for establishing boundary conditions in Bulk System Studies. To mitigate this reliability gap, the Applicability section will be expanded in the second posting of the standard to include a significant MVA percentage of generation regardless of technology.			
Indiana Municipal Power Agency	Yes agree with approach and the 5% capacity factor		A small utility owns a GE 7EA Turbine/Generator with a nameplate rating of 101 MVA in the Eastern Interconnection. The utility uses it as a peaking unit and the capacity factor for the unit averages less than five percent over the last three years. Obviously, this unit does not play a vitale role in maintaining the reliability of the BES. Therefore, why make this utility spend thousands of dollars on testing a machine that is not important to reliability. By using a capacity factor of 5%, this unit will be exempt from this standard.
Response: Thank you for your comments. The SDT agrees that the proposed thresholds, including the 5% capacity factor, will result in verification of models that are necessary for the reliability of the BES.			
Hydro-Québec	Yes agree with		We agree with this approach to exclude units with

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
TransEnergie (HQT)	approach and the 5% capacity factor		low capacity factors provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. Cases exist where large generating units with low capacity factors are operated only during the most stressed operating conditions. In such cases accurate modeling of these units may be critical to reliable operation of the bulk electric system.
Response: Thank you for your comments**.** The SDT has revised the draft standard to allow the Planning Coordinator to identify, through a process demonstrating technical justification, additional generating units that are critical for reliability beyond the applicability criteria established by section 4.2.			
Southwest Power Pool Generation Working Group	Yes agree with approach and the 5% capacity factor		
Dominion	Yes agree with approach and the 5% capacity factor		
Kansas City Power & Light	Yes agree with approach and the 5% capacity factor		
MRO NERC Standards Review Subcommittee	Yes agree with approach and the 5% capacity factor		
Entergy Fossil Operations	Yes agree with approach and the 5% capacity factor		

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
FirstEnergy	Yes agree with approach and the 5% capacity factor		
FEUS	Yes agree with approach and the 5% capacity factor		
Luminant Power	Yes agree with approach and the 5% capacity factor		
Exelon Corporation	Yes agree with approach and the 5% capacity factor		
Cowlitz County PUD	Yes agree with approach and the 5% capacity factor		
E.ON U.S.	Yes agree with approach and the 5% capacity factor		
AWEA	Yes agree with approach and the 5% capacity factor		
American Wind Energy Association	Yes agree with approach and the 5% capacity factor		
Arizona Public Service Co.	Yes agree with approach and the		

Organization	Yes or No	Question 7 Comments and/or Supporting Data for Not Agreeing with a Capacity Factor Exemption:	Question 7 Supporting Data for the Proposed 5% Capacity Factor:
	5% capacity factor		
Wisconsin Electric	Yes agree with approach and the 5% capacity factor		
Dynegy	Yes agree with approach and the 5% capacity factor		
Northeast Utilities	Yes agree with approach and the 5% capacity factor		
Reliant Energy	Yes agree with approach and the 5% capacity factor		
Southern California Edison	Yes agree with approach and the 5% capacity factor		
Xcel Energy	Yes agree with approach and the 5% capacity factor		
Brazos Electric Power Cooperative	Yes agree with approach and the 5% capacity factor		
American Transmission Company	Yes agree with approach and the 5% capacity factor		

8. The SDT is of the opinion, based upon sound engineering judgment, that verifying models for excitation systems of generators per the MVA thresholds specified in the Applicability section 4.1.1 will ensure satisfactory performance of Interconnection network simulation models. Do you agree with this approach? If yes, please provide any data in support of the proposed approach including supporting data that the MVA thresholds specified in the Applicability section 4.1.1 correspond to 80% of the Interconnection MVA.

Summary Consideration:

The majority of responder comments support the concept of requiring excitation control system model verifications for units based on unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA. Some of the affirmative comments were qualified by a desire to allow a transmission entity to identify additional units for verification. This potential is addressed as a new draft process that allows the Planning Coordinator to identify additional units with excitation control system performance that affects a stability limit and/or does not match measured unit response (refer to Question 9 responses for additional details). Based on industry comments received, the SDT is proposing a modification to the Applicability section to additionally include a significant MVA percentage of all generation of all technologies, including Variable Energy Resources.

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
NERC Event Analysis & Information Exchange staff	No, instead use the approach below:	There are a number of units that, through switching, can operate in multiple interconnections, making it hard to decide where they belong.To reduce complexity in administration, avoid confusion, and to have a more level playing field in North America, the standard registration thresholds of units ? 20 MVA per machine and ? 75 MVA per plant should be applied.
Response: Thank you for your comments. Although Field Test results did confirm that verification of excitation system models does result in higher quality dynamics data, it was also noted that verification of excitation system is expensive both from a monetary and human resource viewpoint. Therefore, the SDT believes that these applicability thresholds will result in substantial accuracy improvements to the excitation models and associated Reliability, while not unduly mandating costly and time-consuming verification efforts. The SDT agrees there may be a small number of units that can be switched between two interconnections. These units will follow the more stringent of the two associated requirements. The SDT believes that applicability as written would cover the bulk of installed generators to adequately provide higher quality dynamic data.		
FirstEnergy	No, instead use the approach below:	We feel that 80% of the Interconnection MVA is not high enough. The issue might be not including many of the CC/CT units that have a low capacity factor (above 5%). The team may want to consider 90% or further validate the 80% value.
Response: Thank you for your comments. The 80% threshold has been overwhelmingly accepted by the industry. Also, based on industry responses and the SDT's concerns about a potential reliability gap, the SDT is proposing a modified Applicability section to include a significant MVA percentage of all generation of all technologies, which will additionally include approximately 80% of Variable Energy Resource plants. The SDT has developed a new draft requirement that		

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units whose excitation control system performance affects a stability limit, and/or does not match measured unit response.		
FEUS	No, instead use the approach below:	If the modeling methods are approved and are valid, why do entities have to prove they are right? Test the models on several units of different sizes and configurations to determine their accuracy. If modeling methods aren't accurate, fix them instead of requiring the industry go through the huge expence of testing hundreds of units that have been previously modeled. I also don't see the rationale for the differences in MVA testing requirements between RRCs. The 200 MVA rating for facilities (as specified for the eastern systems) should be the same if this standard is adopted.
Response: Thank you for your comments. The SDT strongly believes that re-occurring validation of the excitation system is necessary to validate system performance for dynamic conditions. This process will also validate any changes and modifications to the excitation system. The SDT has also provided opportunity for an alternative method of ambient monitoring. Generator Owners are permitted to utilize operating data for validation purposes.		
Wisconsin Public Service	No, instead use the approach below:	The provisions of multiple generators at one location requiring testing of units above 20MVA rating puts too much ownerous on operators at CT sites with multiple small CT's that would act differently during an event and have minimal effect on the dynamic models.
Response: Thank you for your comments. The SDT has included in a Periodicity Attachment of the draft standard, a provision for testing multiple similar units. Verification of one unit from a group of units equal to and less than 350 MVA with identical applicable components and settings at the same physical location is sufficient. One of the key conclusions from this draft standard's Field Test is that excitation system verification results in an improvement of the accuracy of the exciter models used in dynamic simulations. If there are multiple CTs at a plant site such that the plant threshold in the Applicability section of the draft standard is exceeded, then the interconnected MVA at that plant site is likely to be a significant influence of the dynamic behavior of the local area. Thus, in order to allow for proper quantification of reliability limits, the SDT believes that excitation model verifications for such a plant site is appropriate. Typically, some of these CTs fall under the criteria specified in the Periodicity Attachment of the draft standard, which could minimize verification activities.		
American Electric Power	No, instead use the approach below:	The need for excitation data and model verification has been driven by plant and system stability needs. We believe that the applicability in the standard should be driven by the same. We would go so far as to suggest that identification of applicable units should be determined by the TP and PC through a process that includes planning study results and operating experience, and that the standard should not specify a blanket applicability unrelated to the stability driven need.
Response: Thanks you for your comment. The 80% threshold has been overwhelmingly accepted by the industry. The SDT has developed a new draft requirement that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control		

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
system performance that affects a stability limit, and/or does not match measured unit response.		
Wisconsin Electric	No, instead use the approach below:	In light of the size and density of the Eastern Interconnection, we are of the opinion that the MVA threshold for units should be raised to 150 MVA or higher.
Response: Thank you for your comments The SDT believes that the MVA thresholds provided in the draft standard will adequately addresses BES system reliability needs. The SDT will be glad to review any technical data provided to support your position.		
AESO	No, instead use the approach below:	Section 4.1.1.2 directly references the Western Interconnection but then uses equipment sizes as a base that far exceeds the ones used by WECC in the Generating Unit Model Validation Policy.75 MVA units vs 10MVA by WECC20 MVA units in a 150 MVA facility vs. 20 MVA facility by WECC 100 kV interconnection vs. 60 kV by WECCPerhaps the standard can reference the WECC guidelines.
Response: Thank you for your comments. Field Test has confirmed that verification of excitation system models does result in higher quality dynamics data. The Field Test also noted that verification of the excitation system is expensive both from a monetary and human resource viewpoint. Therefore, the SDT believes that these applicability thresholds will result in substantial accuracy improvements to the excitation models and associated Reliability- based limits determined by dynamic simulations, while not unduly mandating costly and time-consuming verification efforts.		
American Transmission Company	No, instead use the approach below:	The threshold should be based on NERC registration criteria for Generator Owners/Operators. See Appendix 5 Organization Registration and Certification Manual. (Version 3.3) This criteria should apply across NERC. Item 2 in Requirement 1 should be set to the same level used by NERC's registration criteria for plants.
Response: Thank you for your comments. Field Testing has confirmed that verification of excitation system models does result in higher quality dynamics data. The Field Test also noted that verification of the excitation system is expensive both from a monetary and human resource viewpoint. Therefore, the SDT believes that these applicability thresholds will result in substantial accuracy improvements to the excitation models and associated Reliability-based limits determined by dynamic simulations, while not unduly mandating costly and time-consuming verification efforts.		
US Bureau of Reclamation	No, instead use the approach below:	We believe the NERC Compliance Registry Criteria should be used as the threshold.

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
Response: Thank you for your comments. The SDT does not agree with the view that the Compliance Registry should be the sole basis for determining applicability of Reliability Standards. The SDT has made an ongoing effort to refine the applicability section of the standard in line with one of the guiding principles of NERC's Reliability Standards development process which is the principle that the obligations or requirements of a standard must be material to the Bulk Electric System reliability and measurable. Field Testing has confirmed that verification of excitation system models result in higher quality dynamics data. The Field Test also noted that verification of the excitation system is expensive both from a monetary and human resource viewpoint. Therefore, the SDT believes that these applicability thresholds will result in substantial accuracy improvements to the excitation models and associated Reliability -based limits determined by dynamic simulations, while not unduly mandating costly and time-consuming verification efforts. The vast majority of industry comments indicate agreement.		
Reliant Energy	No, instead use the approach below:	Each unit (including synchronous condensers) 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 15% over the last three calendar years.Each unit (including synchronous condensers) 50 MVA within a plant 250 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 15%
Response: Thank you for your comments. Field Testing has confirmed that verification of excitation system models does result in higher quality dynamics data. The Field Test also noted that verification of excitation system is expensive both from a monetary and human resource viewpoint. Therefore, the SDT believes that these applicability thresholds will result in substantial accuracy improvements to the excitation models and associated Reliability- based limits determined by dynamic simulations, while not unduly mandating costly and time-consuming verification efforts.		
Northeast Power Coordinating Council	Yes	We agree with the general approach to base the number and size of applicable generating units on the objective of validating models for 80 percent of the installed capacity on an Interconnection provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. In the event the Planning Coordinator or Transmission Planner is not permitted to identify additional units, the objective should be changed to validate models for a greater percentage of the installed capacity. We do not have data to verify whether the unit size thresholds specified in Requirement R4.1.1 correspond to 80 percent of the installed capacity on an interconnection, and respectfully suggest that it is the responsibility of the SDT to provide such verification.
Response: Thank you for your comments. The 80% threshold has been overwhelmingly accepted by the industry. Also, based on industry responses and concerns about a potential reliability gap, the SDT is proposing a modified Applicability section to include a significant MVA percentage of all generation of all technologies, which will additionally include approximately 80% of Variable Energy Resource plants. The SDT has developed a new draft requirement that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance that affects a stability limit and/or does not match measured unit response.		

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
SERC Dynamics Review Subcommittee (DRS)	Yes	The MVA values should be coordinated with the MVA thresholds in MOD-10 to MOD-12 and in proposed TPL-001 standards. Supporting data (circa 2003) can be found from the link below which provides a spreadsheet titled Existing Generating Units in the United States by State, Company and Plant, 2003.http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/gu_tabs.htmlThis spreadsheet can be sorted and summed to get an estimate of the percentage generation that would be included. A preliminary look by the DRS suggests that 80% or more would be included.
Response: Thank you for your comments. The SDT appreciates the supporting data reference you have provided. NERC's work plan for the MOD standards will be addressed by Project 2010-03. It is acknowledged that the MVA thresholds must be considered when the MOD standards are revised, including the current SDT work on the TPL-001 through TPL-004 standards. The GV SDT believes that each standard has its unique reliability purpose. The applicability section of the standard for the listed entities should be established according to its purpose and the risk associated with individual requirements. For example, standards MOD-010 and MOD-012 deal with the provision of data for dynamic modeling so the applicability of these standards to smaller units and facilities is quite appropriate. On the other hand, standard MOD-026 deals with mandatory periodic verification of models and data, which is a different exercise, driven by different needs. Based on these needs, the SDT continues to advocate the 80% threshold.		
Dominion	Yes	The proposed threshold captures at least 80.5% of the generators owned by Dominion.
Response: Thank you for your comment. The SDT acknowledges your affirmation for the MVA thresholds corresponding to 80% or great of the interconnected MVA owned by Dominion.		
Constellation Power Generation & Constellation Nuclear	Yes	We agree with the general approach to base the number and size of applicable generating units on the objective of validating models for 80 percent of the installed capacity on an Interconnection provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. In the event the Planning Coordinator or Transmission Planner is not permitted to identify additional units, the objective should be changed to validate models for a greater percentage of the installed capacity. We do not have data to verify whether the unit size thresholds specified in Requirement R4.1.1 correspond to 80 percent of the installed capacity on an interconnection, and respectfully suggest that it is the responsibility of the SDT to provide such verification.
Response: Thank you for your comments. The 80% threshold has been overwhelmingly accepted by the industry. Also, based on industry responses and concerns about a potential reliability gap, the SDT is proposing a modified Applicability section to include a significant MVA percentage of all generation of all technologies, which will additionally include approximately 80% of Variable Energy Resource plants. The SDT has developed a new draft requirement that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance that		

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
affects a stability limit and/or does not match measured unit response.		
Progress Energy, Inc.	Yes	However, the MVA values MUST be coordinated with the MVA thresholds in MOD-010 to 012 and in proposed TPL-001 standards. Supporting data (circa 2003) can be found from the link below which provides a spread sheet titled Existing Generating Units in the United States by State, Company and Plant, 2003.http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/gu_tabs.html
Response: Thank you for your comments. The SDT appreciates the reference to the statistical data. NERC's work plan for MOD standards will be addressed by Project 2010-03. It is acknowledged that the MVA thresholds must be considered when the MOD standards are revised, including current SDT work on the TPL-001 through TPL-004 standards. The GV SDT believes that each standard has its unique reliability purpose. The applicability section of the standard for the listed entities should be established according to its purpose and the risk associated with individual requirements. For example, standards MOD-010 and MOD-012 deal with the provision of data for dynamic modeling so the applicability section of these standards to smaller units and facilities is quite appropriate. On the other hand, the standard MOD-026 deals with mandatory periodic verification of models and data, which is a different exercise, driven by different needs. Based on these needs, the SDT continues to advocate the 80% threshold.		
Dynegy	Yes	We support SDT's approach to include aggregate MVA values. We also would like to suggest minor wording changes for SDT consideration to revise the language in the draft standard to better reflect an aggregate MVA approach. The word "same" is added to draft standard language as following: " Each unit (including synchronous generators) => 100 MVA, connected at the SAME point of interconnection at 100 Kv or above and with an".
Response: Thank you for your comments. The draft standard has been revised based on your comments and the word, "same" was added in the applicability section of the standard.		
Reliant Energy	Yes	The SDT at least has done an engineering analysis in developing the MVA thresholds. I am not sure that registration criteria was done in the same manner.
Response: Thank you for your comments. The SDT appreciates your comment..		
ISO New England Inc.	Yes	Currently generators over 100 MVA make up about 85% of the installed generator capacity in New England. Concentration on these units should provide an accurate representation of the system. Efforts to verify lower MVA capacity units would provide limited benefit for the work involved.
Response: Thank you for your comments. The SDT appreciates your comment..		

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
Ameren	Yes	(1) We believe the MVA thresholds are appropriate and pick up the vast majority of interconnection (MVA). However, the MVA values MUST be consistent with the MVA thresholds in other stanadrds, such as MOD-10 to 12. and in proposed TPL-001 standards. (2) Supporting data (circa 2003) can be found from the link below which provides a spread sheet titled Existing Generating Units in the United States by State, Company and Plant, 2003. http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/gu_tabs.htmlThe spreadsheet can be sorted and summed to get an estimate of the percentage generation that would be included. A preliminary look suggests that 80% or more would be included.
Response: Thank you for your comments. The SDT appreciates the reference to the statistical data. NERC's work plan for the MOD standards will be addressed by Project 2010-03. It is acknowledged that the MVA thresholds must be considered when any standard is developed or revised, as each standard has its unique reliability purpose. The applicability of the standard for the listed entities should be established according to its purpose and the risk associated with individual requirements. For example, standards MOD-010 and MOD-012 deal with the provision of data for dynamic modeling so the applicability of these standards to smaller units and facilities is quite appropriate. On the other hand, the standard MOD 026 deals with mandatory periodic verification of models and data, which is a different exercise, driven by different needs. Based on these needs, the SDT continues to advocate the 80% threshold.		
Duke Energy	Yes	We agree with the approach, but would also caution the team to consider the future composition of the Interconnection MVA. Possibly the team already considered newer types of generation and the benefit of a verified model rather than just estimated or typical manufacturers dynamics data (MOD-013). The team should consider clarifying the relationship between the terms in MOD-013 and MOD-026. Is unit-specific dynamics data equivalent to a verified model? Even in the case of a sister unit? If a unit does not meet the applicability for MOD-026 would they then follow MOD-013 to determine the applicable model to provide?
Response: Thank you for your comments. Unit-specific data, referenced in standard MOD-013, is not the same as a verified model. It is possible for a new unit to be installed at a site where another unit has already been installed and that all units meet the criteria in standard MOD-026 – Attachment 1 "Excitation Control System Model Verification Periodicity" Scenario 3 where one verification would meet the requirements of the draft standard. However, it is also recognized that Interconnection Agreements may often result in the verification of models as a condition of being able to interconnect to a transmission provider's system. Finally, if a new unit does not meet the applicability of standard MOD-026, then at a minimum they would be required to follow standard MOD-013 requirements to determine the applicable model to provide.		
Hydro-Québec TransEnergie (HQT)	Yes	We agree with the general approach to base the number and size of applicable generating units on the objective of validating models for 80 percent of the installed capacity on an Interconnection provided that Planning Coordinators or Transmission Planners are allowed to identify additional applicable units beyond those specified in section 4.1.1 based on criticality to system reliability. In the event the Planning Coordinator or Transmission Planner is not

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
		permitted to identify additional units, the objective should be changed to validate models for a greater percentage of the installed capacity. We do not have data to verify whether the unit size thresholds specified in Requirement R4.1.1 correspond to 80 percent of the installed capacity on an interconnection, and respectfully suggest that it is the responsibility of the SDT to provide such verification.
Response: Thank you for your comments. The SDT has developed a new draft requirement that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance that affects a stability limit and/or does not match measured unit response.		
IRC Standards Review Committee	Yes	We do not have any technically sound alternatives to suggest.
Response: Thank you for your comment.		
Independent Electricity System Operator	Yes	We do not have any technically sound alternatives to suggest.
Response: Thank you for your comment.		
Consumers Energy Company	Yes	We believe the MVA thresholds are appropriate and pick up the vast majority of interconnection (MVA).
Response: Thank you for your comments. The SDT appreciates your comment.		
Southern Company	Yes	See comment on 7 above.
Response: Thanks you for your comment. The SDT has referred to the comment referenced.		
Kansas City Power & Light	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Pepco Holdings, Inc (PHI) - Affiliates	Yes	

Organization	Yes or No	Question 8 Supporting Data or Alternate Approach
Entergy Fossil Operations	Yes	
Luminant Power	Yes	
Exelon Corporation	Yes	
Cowlitz County PUD	Yes	
E.ON U.S.	Yes	
AWEA	Yes	
American Wind Energy Association	Yes	
Arizona Public Service Co.	Yes	
Manitoba Hydro	Yes	
Northeast Utilities	Yes	
Southern California Edison	Yes	
Indiana Municipal Power Agency	Yes	
Xcel Energy	Yes	

9. Do you believe the SDT should develop a Requirement to allow the Transmission Planner or the Planning Coordinator to identify additional applicable units beyond those specified in section 4.1.1 due to their criticality to the reliability of the Bulk Electric System? If yes, please include the criteria that should be used by the Transmission Planner or Planning Coordinator to identify critical units with MVA rating less than listed in section 4.1.1 and any supporting data.

Summary Consideration:

More than half of the industry respondents representing all regions recommend inclusion of units identified by either the Transmission Planner or Planning Coordinator based on clear technical study results documenting the impact on the BES. In response, the SDT has drafted a process in the 2nd draft of the standard (reference Requirement R5) that requires technical justification but which allows the Planning Coordinator to identify additional units whose excitation control system performance requires scrutiny by the Generator Owner. In some instances, scrutiny by the Generator Owner could lead to corrected model data that could meet the needs of the Planning Coordinator. But unless the Generator Owner can determine that the existing model structure and data requires a correction and that meets the needs of the Planning Coordinator, the model must be verified. The SDT originally considered letting the Transmission Planner identify critical units along with the Planning Coordinator. However, the SDT realized that the Transmission Planner could bring model issues to the attention of its Planning Coordinator; then the Planning Coordinator could make a determination if the model issue warranted further review by the Generator Owner, thus adding another inherent “check” in the process.

Organization	Yes or No	Question 9 Comment or Supporting Data
SERC Dynamics Review Subcommittee (DRS)	No	Add a new section under Applicability 4.1.1.5 stating Generating facilities that do not meet the applicability requirements of 4.1.1.1 - .4 may be included when their performance is found to reduce the reliability of the BES by the applicable Transmission Planning Authority. A written request provided by the Transmission Planning Authority shall include the technical basis for any such inclusion (e.g. must run, reliability, voltage, or stability needs).
Response: Thank you for your comments. The SDT does agree with the basic concept, including the need for the transmission entity to provide a technical basis to support the identification of additional units required to provide a corrected model or perform excitation control system verification. The SDT has developed a new draft process that outlines a process that requires technical documentation but which allows the Planning Coordinator to identify additional units as supported by technical justification.		
Luminant Power	No	The SDT is tasked with developing requirements for applicability across North America. Regions have the ability to develop more stringent requirements based on regional needs, and through various regional requirements development processes. Allowing the Transmission Planner or Planning Coordinator to expand the applicability

Organization	Yes or No	Question 9 Comment or Supporting Data
		of the NERC Standard on an individual resource basis (without industry input, balloting, etc.) would circumvent the FERC approved procedures for development of reliability standards.
Response: Thank you for your comments. The SDT believes that the reliability of the BES could be put at risk if there is no mechanism to allow for the correction of models that do not accurately represent expected equipment performance. However, the new process (reference Requirement R5 in the revised standard) that has been drafted by the SDT requires technical justification for a limited number of scenarios.		
E.ON U.S.	No	The generation owner/operator is in the best position to identify those facilities that require verification studies. Transmission providers should not be allowed to independently impose compliance obligations upon other parties. Any process to allow imposition of additional compliance responsibilities should be overseen by the appropriate regional reliability organization.
Response: Thank you for your comments. The SDT believes that the reliability of the BES could be put at risk if there is no mechanism to allow for the correction of models that do not accurately represent expected equipment performance. However, the new process (reference Requirement R5 in the revised standard) that has been drafted by the SDT requires technical justification for a limited number of scenarios.		
AWEA	No	There would have to be very clear technical justification for such a designation or it could be perceived as discriminatory and/or preferential
Response: Thank you for your comment. The SDT believes that the reliability of the BES could be put at risk if there is no mechanism to allow for the correction of models that do not accurately represent expected equipment performance. However, the new process (reference Requirement R5 in the revised standard) that has been drafted by the SDT requires technical justification for a limited number of scenarios.		
Ameren	No	However, add 4.1.1.5 stating Generating facilities that do not meet the applicability requirements 4.1.1.1 - .3 may be included when their performance is found to create or contribute to reduced reliability of the BES when requested by the applicable Transmission Planner. The written request provided by the Transmission Planner shall include the technical basis for any such inclusion (e.g. must run for reliability, voltage, or stability needs).
Response: Thank you for your comments. The SDT agrees with the concept and has developed a process (reference Requirement R2) in the second draft that should address your concern.		
American Transmission Company	No	This standard should apply to all registered GO's and GOP's. A requirement as suggested puts the TP or PA in the position of telling NERC who should be registered. This responsibility that clearly falls to NERC and the Regional Entities and should not be expanded to any registered entity.

Organization	Yes or No	Question 9 Comment or Supporting Data
Response: Thank you for your comments. The SDT believes that the reliability of the BES could be put at risk if there is no mechanism to allow for the correction of models that do not accurately represent expected equipment performance. However, the new process (reference Requirement R5 in the revised standard) that has been drafted by the SDT requires technical justification for a limited number of scenarios.		
Consumers Energy Company	No	
Southern Company	No	
Cowlitz County PUD	No	
FEUS	No	
Southwest Power Pool Generation Working Group	No	
MRO NERC Standards Review Subcommittee	No	
FirstEnergy	No	
Pepco Holdings, Inc (PHI) – Affiliates	No	
Entergy Fossil Operations	No	
Arizona Public Service Co.	No	
Wisconsin Electric	No	
Manitoba Hydro	No	
Dynegy	No	

Organization	Yes or No	Question 9 Comment or Supporting Data
Southern California Edison	No	
Indiana Municipal Power Agency	No	
Brazos Electric Power Cooperative	No	
Reliant Energy	No	
NERC Event Analysis & Information Exchange staff	Yes	It is essential that the Planning Coordinator and Reliability Coordinator be allowed to designate other critical units. In some cases, despite their size, the aggregation of a number of small units can have a significant impact on the dynamics of an area. One example is the transfer capability across the state of Maine, which is influenced by the dynamics of the multiple small hydro units in the state. Similarly, the dynamic performance of small units may be critical to reliability in some local areas such as New Brunswick and Nova Scotia.
Response: Thank you for your comments. More than half of the industry respondents representing all NERC regions recommend inclusion of units by the Transmission Planner or Planning Coordinator based on clear technical justification. The SDT has developed a new draft process (reference Requirement R5) that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance that affects a stability limit and/or does not match measured unit response. Once identified, the Generator Owner can provide corrected excitation control system data or verify the model.		
Northeast Power Coordinating Council	Yes	The Planning Coordinator or Transmission Planner should be permitted to identify additional units for applicability of the Standard based on the results of generator interconnection studies or other studies that demonstrate the criticality of correct settings on system reliability, e.g. studies demonstrating sensitivity of a stability-based System Operating Limit to correct equipment settings and functionality.
Response: Thank you for your comment. Your comment is very similar to a great number of other industry comments in recommending the inclusion of units by the Transmission Planner or Planning Coordinator based on clear technical study results documenting the impact on the BES. In response to these comments the SDT has drafted a new process (reference Requirement R5) that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance requiring scrutiny by the Generator Owner. Unless the Generator Owner can determine that the existing model structure and data requires a correction, the model must be verified.		
Dominion	Yes	If a unit exhibits transient or dynamic instability for an event but the simulation did not show the same then the excitation system shall be tested for units beyond those specified in section 4.1.1.

Organization	Yes or No	Question 9 Comment or Supporting Data
Response: Thank you for your comments. The SDT has developed a new process (reference Requirement R5) which outlines a process that requires technical documentation, including identification of units which do not perform as predicted by the current excitation control system model, that allows the Planning Coordinator to identify additional units that the Generator Owner would either provide a corrected or a verified model.		
IRC Standards Review Committee	Yes	In some areas on the interconnection, such as those that are sparsely populated, performance of generating units at less than 100 MVA might be critical to reliability.
Response: Thank you for your comments. The SDT agrees with this and other comments that there are situations where the verification of excitation control system is necessary to ensure the accuracy of BES security limits. In response to these comments, the SDT has drafted a new process (reference Requirement R5). This process allows the Planning Coordinator to identify through technical justification additional units with excitation control system model requiring correction or verification. The development of technical documentation is required to ensure this request is warranted.		
AESO		The AESO agrees with the SRC ISO/RTO comments.
Response: Thank you for your comment. The SDT was unable to identify the SRC ISO/RTO comment referenced. Please refer to the intended comment for the SDT response provided..		
Exelon Corporation	Yes	Exelon is concerned about the use of the term "critical" in this context because it implies the same level of criticality that would be used to put a station on the critical asset list. A small generating station may be sufficiently close to another station that it affects the dynamic behavior of the generators at the second station. The Transmission Planner should be able to identify the units at the smaller station as applicable to the standard without calling them critical units. Exelon does appreciate the need for guidelines regarding the units that can be indentified as applicable to MOD-026.
Response: Thank you for your comments. The SDT has developed a new process (reference Requirement R5) that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance that affects a stability limit and/or does not match measured unit response. Once identified, the Generator Owner can provide corrected excitation control system data or verify the model. The term “critical” is not used in the new draft requirement.		
Constellation Power Generation & Constellation Nuclear	Yes	The Planning Coordinator or Transmission Planner should be permitted to identify additional units for applicability of the Standard based on the results of generator interconnection studies or other studies that demonstrate the criticality of correct settings on system reliability, e.g. studies demonstrating sensitivity of stability based System Operating Limit to correct equipment settings and functionality.
Response: Thank you for your comments. The SDT agrees this type of requirement is needed and has included process (reference Requirement Rr) in the		

Organization	Yes or No	Question 9 Comment or Supporting Data
second draft.		
Wisconsin Public Service	Yes	Determined critical in the model or in a constrained area of the system.
Response: Thank you for your comments. The SDT agrees and has drafted a new process (reference Requirement R2) to address this concern.		
American Electric Power	Yes	Criteria should be units or plants whose operation is limited by transient or small-signal instability or that are located in areas that may be subject to stability constraints. Why not rather impose the applicability in the fashion of what is being asked here, that the TP and PC identify through a process which units should be verified, not blanket applicability as is in the current draft.
Response: Thank you for your comments. More than half of the industry respondents representing all NERC regions recommend inclusion of units by the Transmission Planner or Planning Coordinator based on clear technical justification. The SDT has developed a new draft requirement that outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance that affects a stability limit and/or does not match measured unit response. Once identified, the Generator Owner can provide corrected excitation control system data or verify the model.		
Progress Energy, Inc.	Yes	Add to Applicability a 4.1.1.4 stating Generating facilities that do not meet the applicability requirements 4.1.1.1 - .3 may be included when their performance is found to create or contribute to reduced reliability of the BES when requested by the applicable Transmission Planning Authority. The written request provided by the Transmission Planning Authority shall include the technical basis for any such inclusion (e.g. must run for reliability, voltage, or stability needs).
Response: Thank you for your comments. The SDT agrees and has developed a new process (reference Requirement R5) in the second draft that should address this concern.		
Reliant Energy	Yes	Units that have an RMR. If they do not have an RMR (in unorganized markets) then how can they be called critical?
Response: Thank you for your comments. More than half of the industry respondents representing all NERC regions recommend inclusion of units by the Transmission Planner or Planning Coordinator based on clear technical justification. The SDT has developed a new process (reference Requirement R5) which outlines a process that requires technical justification but which allows the Planning Coordinator to identify additional units for certain scenarios. Once identified, the Generator Owner can provide corrected excitation control system data or verify the model.		
Duke Energy	Yes	Add a similar requirement to R11 that allows the TO or RC to add a generator that does not meet the applicability

Organization	Yes or No	Question 9 Comment or Supporting Data
		criteria when their performance is found to create or contribute to reduced reliability. No one can foresee all future system configurations and operating conditions. This type of requirement is fundamental to analyzing and resolving issues. Additional Comment on R11 and R12. When system or plant events occur impacting transient voltage response, the GOP should evaluate actual unit/plant performance against expected performance. This is especially important when taking credit for sister units to avoid testing of similar units at the same site. With the long time between verification testing (10 years) and even longer time frame when allowing for claiming sister units, it is important to assess actual versus predicted performance. It is not sufficient to have only the TO or RC identify potential issues because they would normally only recognize issues that negatively impact the entire system and only for the specific event. Individual generating stations may have not behaved as modeled due to protection/control problems but the overall system met requirements.
Response: Thank you for your comments. The SDT has developed a new process (reference Requirement R5) that requires technical documentation but which allows the Planning Coordinator to identify additional units as supported by technical justification. This includes the scenario when the simulated unit response does not match measured unit response. There are currently no provisions for the Generator Owner to evaluate actual performance during a transient voltage response type of event, unless it is through observation of performance. The SDT believes that while your suggestion represents good utility practice, it is beyond the scope of this standard.		
Hydro-Québec TransEnergie (HQT)	Yes	The Planning Coordinator or Transmission Planner should be permitted to identify additional units for applicability of the Standard based on the results of generator interconnection studies or other studies that demonstrate the criticality of correct settings on system reliability, e.g. studies demonstrating sensitivity of a stability based System Operating Limit to correct equipment settings and functionality.
Response: Thank you for your comments. The SDT agrees and has drafted a new process (reference Requirement R5) to address your comment.		
Xcel Energy	Yes	Yes, we agree, however the SDT needs to give consideration to whether the Generator Owner has any rights to dispute such designation from its TP or PC.
Response: Thank you for your comments. The SDT agrees that the reliability of the BES could be put at risk if there is no mechanism to allow for the correction of models that do not accurately represent expected equipment performance. In order to ensure that the mechanism is not misused, a new requirement has been drafted by the SDT that requires technical justification for a limited number of scenarios.		
Independent Electricity System Operator	Yes	In some areas on the interconnection, such as those that are sparsely populated, performance of generating units at less than 100 MVA might be critical to reliability. The criteria to allow the TP and PC to identify these units could include: a. A 5% or 10% deviation of any or several of the excitation system's parameters/settings could make an otherwise stable simulation to be unstable; b. Use of generic models for the excitation system or

Organization	Yes or No	Question 9 Comment or Supporting Data
		generator would make an otherwise stable simulation to be unstable. c. Other changes or incorrect assumptions for the excitation system or generator would make an otherwise stable simulation to be unstable.
Response: Thank you for your comments. After reviewing provided details, the SDT encourages you to review the new process draft (reference Requirement R2) and provide additional comments as appropriate.		
US Bureau of Reclamation	Yes	If a unit or facility is critical to reliability and the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator can present convincing evidence, the plant should be included. The criteria to use should be developed by the above entities.
Response: Thank you for your comments. The SDT agrees and has drafted a new requirement that outlines a process requiring technical justification but which allows the Planning Coordinator to identify additional units with excitation control system performance requiring scrutiny by the Generator Owner. Unless the Generator Owner can determine that the existing model structure and data requires a correction, the model must be verified.		
Kansas City Power & Light	Yes	
American Wind Energy Association	Yes	
Northeast Utilities	Yes	

10. The SDT is proposing an implementation plan that requires certain percentages of applicable units to be verified two, six, and eleven years after the standard is approved. The SDT also thought it would be prudent to allow the verification of excitation systems per Regional Entity procedures and guidelines within 5 years of the approval date to be sufficient for demonstrating compliance with this new Reliability Standard.

Do you agree with these approaches?

Summary Consideration:

While industry is in general agreement with the principles of the proposed implementation plan, concern was expressed regarding development time for processes this standard would require. The SDT decided to extend the initial timeframe following standard approval for model verification from “2 years following regulatory approval, 10% of its applicable units per Interconnection on a MVA basis” to “4 years following regulatory approval, 30% of its applicable units per Interconnection on a MVA basis”.

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
American Electric Power	No, instead of allowing credit for verification of excitation systems within the last 5 years of the Standard’s approval date, instead would recommend (please specify below)	that the areas with the greatest instability be addressed first.
Response: Thank you for your comment. The SDT was not able to interpret your comment and therefore could not provide a response.		
Northeast Power Coordinating Council	No, the phase in period for unit excitation system verification should be (please specify below)	The proposed impmentation plan is too long. We recommend a five-year implementation with a requirement that units representing 20 percent of installed capacity be tested each year. We are concerned that an eleven-year implementation plan does not adequeately promote system reliability, and that having only three milestones will place a burden on system operators to schedule testing because Genator Owners may wait until years two, six, and eleven to schedule testing instead of spreading the tests out over the implementation period.The form will not accept more than one box checked above, but "Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date" should be checked.

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
Response: Thank you for your comments. The SDT believes, and the majority of industry responders agreed, that the current implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a 5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications. System operators are not necessarily required nor expected to be involved in scheduling model verification. The Generator Owner will determine the verification method and most likely related testing will be done with the unit off line as part of a scheduled maintenance outage; which will result in testing being satisfactorily distributed over the 11 year phase-in period. The SDT notes your concurrence with allowing credit for model verification occurring within the last 5 years of the Standard approval date.		
SERC Dynamics Review Subcommittee (DRS)	No, the phase in period for unit excitation system verification should be (please specify below)	The first time period should be 3 years (10%). It is anticipated that testing of the first units will take significantly longer than subsequent testing. Although this factor may have been considered in the proposed time periods, other factors such as the potential shortage of testing services at the beginning of the testing window may not have been considered.
Response: Thank you for your comments. The second draft of the standard extends the initial timeframe following standard approval for compliance to 4 years (which includes a one year allowance to allow entities time to put processes in place) for verifying 30% of required units. The SDT believes this additional time will better position the Generator Owners to leverage the planned outage schedule.		
IRC Standards Review Committee	No, the phase in period for unit excitation system verification should be (please specify below)	We suggest that the usual implementation language be used. Requirement R1 sets the schedule for verification even for the first time based on a 10-year cycle (we suggest to be shortened to 5 years, especially for the analog and rotating type exciters). We agree with allowing credits for verification of excitation systems within the last 5 years of Standard's approval date.
Response: Thank you for your comments. The SDT believes, and the majority of industry responders agreed, that the current implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a 5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications.		
Consumers Energy	No, the phase in period for unit excitation system	The phase-in period of 2 years is likely to be insufficient unless there are significantly more consultants available than we think there are, as many Generator

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
Company	verification should be (please specify below)	Operators may need to hire a severely constricted resource.
Response: Thank you for your comment. The second draft of the standard extends the initial timeframe following standard approval for compliance to 4 years (which includes a one year allowance to allow entities time to put processes in place) for verifying 30% of required units. The SDT believes this additional time will better position the Generator Owners to leverage the planned outage schedule.		
Dynegy	No, the phase in period for unit excitation system verification should be (please specify below)	If the Generator Owner is assigned the responsibility for model verification, there will not be enough consultants to handle the resulting workload placed on Generator Owners.
Response: Thank you for your comment. The SDT recognizes the issue with assigning responsibility for model verification and has extensively discussion the issue. The collective industry response to Question 1 did not indicate significant issue with the Generator Owner being responsible for model verification. Nevertheless, in response to a number of industry responders regarding the transition period, The second draft of the standard extends the initial timeframe following standard approval for compliance to 4 years (which includes a one year allowance to allow entities time to put processes in place) for verifying 30% of required units. The SDT believes this additional time will better position the Generator Owners to leverage the planned outage schedule.		
Northeast Utilities	No, the phase in period for unit excitation system verification should be (please specify below)	We recommend a five or ten-year implementation with a requirement that units representing 20 or 10 percent, respectively, of installed capacity be tested each year. We are concerned that having only three milestones will place a burden on system operators to schedule testing because Genator Owners may wait until years two, six, and eleven to schedule testing instead of spreading the tests out over the implementation period.
Response: Thank you for your comments. Your response indicates that you are not necessarily opposed to a 10 year implementation plan however you are concerned that the scheduling flexibility afforded by not having yearly milestones would allow Generator Owners to procrastinate and perform model verification activities at the last minute. Keep in mind the majority of industry appears to agree with the SDT that the milestones specified are appropriate because a) the first milestone provides Generator Owners preparation time for performing model verification, including the potential to develop in-house expertise; and b) the milestones specified allow model verification activities to be performed during scheduled maintenance outages, especially when electing to perform staged tests. The SDT expects the Generator Owner to manage model verification scheduling in a responsible manner to remain compliant.		
ISO New England Inc.	No, the phase in period for unit excitation system verification should be (please specify below)	2-1/2 years with a 5 year overall renewal of verification.
Response: Thank you for your comments. The SDT believes, and the majority of industry responders agreed, that the current implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a		

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications. Regarding your recommendation to shorten the re-verification cycle to 5 years, the SDT did not find evidence indicating a shorter cycle would materially improve model quality.		
Ameren	No, the phase in period for unit excitation system verification should be (please specify below)	(1) The term "verification" should be defined. Defining "verification" would give Generator Operators/Generator Owners a clearer understanding of what data should be verified in the model.(2) The first time period should be 3 years (10%). It is anticipated that the first units will take significantly longer than subsequent testing. Although this factor is already being considered in proposed time periods, there will probably be a significant shortage of testing services at the beginning of the testing window. (3) The last period for 100% of appliable units should be 12 years to match with 12 years of outage cycle.
Response: Thank you for your comments. The second draft of the standard lists unit-specific information required to be documented following completion of excitation system model verification. This information should resolve any confusion of the term “verification.” Regarding your second comment, the second draft of the standard extends the initial timeframe following standard approval for compliance to 4 years (which includes a one year allowance to allow entities time to put processes in place) for verifying 30% of required units. The SDT believes this additional time will better position the Generator Owners to leverage the planned outage schedule. Your third comment is unique in terms of specifying a 12 year outage cycle. The SDT, support by industry comments, believes that the 10 year implementation timeframe will provide the industry adequate time to verify excitation control system model and data and also develop expertise to perform verification in-house.		
Hydro-Québec TransEnergie (HQT)	No, the phase in period for unit excitation system verification should be (please specify below)	The proposed impmentation plan is too long. We recommend a five-year implementation with a requirement that units representing 20 percent of installed capacity be tested each year. We are concerned that an eleven-year implementation plan does not adequeately promote system reliability, and that having only three milestones will place a burden on system operators to schedule testing because Genator Owners may wait until years two, six, and eleven to schedule testing instead of spreading the tests out over the implementation period.Credit could be allowed for verification of excitation systems within the last five years of the Standards approval date.
Response: Thank you for your comments. The SDT believes, and the majority of industry responders agreed, that the current implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a		

<table>
<tr><th>Organization</th><th>Yes or no</th><th>Question 10 Additional Comments or Recommendations:</th></tr>
<tr><td colspan="3">5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications.

The Generator Owner will determine the verification method and most likely related testing will be done with the unit off line as part of a scheduled maintenance outage; which will result in testing being satisfactorily distributed over the 10 year phase-in period.

Regarding your concern that the scheduling flexibility afforded by not having yearly milestones would allow Generator Owners to procrastinate and perform model verification activities at the last minute. Keep in mind the majority of industry appears to agree with the SDT that the milestones specified are appropriate because a) the first milestone provides Generator Owners preparation time for performing model verification, including the potential to develop in-house expertise; and b) the milestones specified allow model verification activities to be performed during scheduled maintenance outages, especially when electing to perform staged tests. The SDT expects the Generator Owner to manage model verification scheduling in a responsible manner to remain compliant.

The SDT notes your concurrence with allowing credit for verification occurring within the last 5 years of the Standard approval date.</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No, the phase in period for unit excitation system verification should be (please specify below)</td><td>10 years is too long a period to phase in full compliance with this standard. We recommend this be shortened to no more than 5 years so that the continent can have a fully verified set of excitation system data by that time to support modeling and simulation. This has been long overdue, and allowing the 10-year phase in period prolongs achieving the desriable reliability objectives. We also suggest the SDT to consider shortening the re-verificaiton cycle to 5 years.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT does agree that implementation of an enforceable excitation control system model verification standard is overdue. The SDT believes, and the majority of industry responders agreed, that the current implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a 5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications.

The Generator Owner will determine the verification method and most likely related testing will be done with the unit off line as part of a scheduled maintenance outage; which will result in testing being satisfactorily distributed over the 10 year phase-in period.

Also note that through the requirements of standards MOD-012 and MOD-013, the current dynamics database should already be reasonably representative of actual equipment performance.</td></tr>
<tr><td>American Transmission Company</td><td>No, the phase in period for unit excitation system verification should be (please specify below)</td><td>20% per year for the next 5 yesrs.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT believes, and the majority of industry responders agreed, that the current implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform</td></tr>
</table>

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a 5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications.		
US Bureau of Reclamation	No, the phase in period for unit excitation system verification should be (please specify below)	We recommend a 5-year phase in period.
Response: Thank you for your comments. The SDT believes, and the majority of industry responders agreed, that the current implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a 5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications.		
Entergy Fossil Operations	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	I vote yes on both of the questions.
Response: Thank you for your comment. The SDT appreciates your comment.		
AESO	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	The AESO agrees with the SRC ISO/RTO comments.
Response: Thank you for your comment. The SDT was unable to identify the other commenter mentioned – but if their comments are included, please reference the response.		
Wisconsin Public Service	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	At the Web-ex I thought the phase in was 10% per year with 100% by end of yr 11. This makes it sound like a different phase in will be used but no details on % at the 2, 6, and 11 year windows.
Response: Thank you for your comments. For details please see the proposed effective dates in the second draft of the Standard.		
AWEA	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	I agree with both the phase in period and allowing credit for units verified within the last 5 years via regional standards

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
Response: Thank you for your comment. The SDT appreciates your comment.		
Progress Energy, Inc.	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	The first time period should be 3 years (10%). It is anticipated that the first units will take significantly longer than subsequent testing. Although this factor is already being considered in proposed time periods, there will probably be a significant shortage of testing services at the beginning of the testing window.
Response: Thank you for your comments. The second draft of the standard extends the initial timeframe following standard approval for compliance to 4 years (which includes a one year allowance to allow entities time to put processes in place) for verifying 30% of required units. The SDT believes this additional time will better position the Generator Owners to leverage the planned outage schedule.		
Indiana Municipal Power Agency	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	IMPA is concerned about the implementation plan. The 10 percent in two years seems feasible, but what if companies decide to test all their units to save on travel cost of a contractor. Has the SDT looked at the total number of units that are covered by this standard and how many contractors can do this work? For example, if a company owns five or more peaking units in one location or in close proximity, they may decide to test all their units at the same time and pay for only one trip by the contractor. Then the next Generator Operator does the same with its units and this continues to occur throughout the two year time period. This type of mentality may hurt the Generator Operator who owns only one unit and has to wait on an available contractor to perform the test. If the Generator Operator does not get that one unit tested within the first two years, it will be non-compliant with this standard (the Generator Operator only owns one unit that this standard applies).
Response: Thank you for your comments. The second draft of the standard extends the initial timeframe following standard approval for compliance to 4 years (which includes a one year allowance to allow entities time to put processes in place) for verifying 30% of required units. The SDT believes this additional time will better position the Generator Owners to leverage the planned outage schedule.		
NERC Event Analysis & Information Exchange staff	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
Dominion	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
Kansas City Power & Light	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
MRO NERC Standards Review Subcommittee	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
FirstEnergy	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
Constellation Power Generation & Constellation Nuclear	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
E.ON U.S.	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
Arizona Public Service Co.	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
Wisconsin Electric	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
Reliant Energy	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	
Reliant Energy	Yes, agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date	

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
Luminant Power	Yes, agree with proposed phase in period for unit excitation system verification	Note that I also agree with allowing credit for verification of excitation systems within the last 5 years of the Standard's approval. The form would not let me select both yes answers.
Response: Thank you for your comment. The SDT appreciates your comment.		
Southern Company	Yes, agree with proposed phase in period for unit excitation system verification	We agree with both Yes statements above. The software will only allow one to be marked.
Response: Thank you for your comment. The SDT appreciates your comment.		
City of Garland, Garland Power & Light - GOP Registered Entity	Yes, agree with proposed phase in period for unit excitation system verification	Agree with both "Yes" statements - form will only allow one to be selected - if the 2 "Yes" statements are mutually exclusive, then I must not understand your statements & will go with the 1st "Yes"
Response: Thank you for your comment. The SDT appreciates your comment.		
Duke Energy	Yes, agree with proposed phase in period for unit excitation system verification	We wanted to also check "YES" on allowing credit for verification of excitation systems within the last 5 years of the Standard's approval date, but this electronic form wouldn't allow us to do that.
Response: Thank you for your comment. The SDT appreciates your comment.		
Pepco Holdings, Inc (PHI) - Affiliates	Yes, agree with proposed phase in period for unit excitation system verification	
Southwest Power Pool Generation Working Group	Yes, agree with proposed phase in period for unit excitation system verification	
FEUS	Yes, agree with proposed phase in period for unit excitation system verification	
Cowlitz County PUD	Yes, agree with proposed phase in period for unit excitation system verification	

Organization	Yes or no	Question 10 Additional Comments or Recommendations:
Exelon Corporation	Yes, agree with proposed phase in period for unit excitation system verification	
American Wind Energy Association	Yes, agree with proposed phase in period for unit excitation system verification	
Manitoba Hydro	Yes, agree with proposed phase in period for unit excitation system verification	
Southern California Edison	Yes, agree with proposed phase in period for unit excitation system verification	
Xcel Energy	Yes, agree with proposed phase in period for unit excitation system verification	

11. If you are aware of any regional variances that would be required as a result of this standard, please identify them here.

Summary Consideration:

No regional variances were identified by industry.

Organization	Yes or No	Question 11 Regional Variance and Comment
Northeast Power Coordinating Council		None.
Dominion		SERC - supplement requires members to validate the excitation system model parameters of their generating units within 7 years (dated 2007).MRO draft guideline in field test, not currently in effect.
Response: Thank you for your comment. The SERC DRS has been notified by the SDT. The SERC DRS indicates they do not have plans to pursue a Regional Variance.		
Kansas City Power & Light		Not aware of any regional differences.
Response: Thank you for your comment.		
MRO NERC Standards Review Subcommittee		No
IRC Standards Review Committee		None
Luminant Power		Possible regional variance on applicability with GOP vs. GO in ERCOT.
Response: Thank you for your comment. Based on guidance provided by the FMWG, the SDT has designated the Generator Operator as the applicable entity in the second posting of the standard.		
Constellation Power Generation & Constellation Nuclear		None.

Organization	Yes or No	Question 11 Regional Variance and Comment
Consumers Energy Company		N/A
American Electric Power		No known need for regional variances
Response: Thank you for your comment.		
Manitoba Hydro		none
Progress Energy, Inc.		No.
Dynegy		None at this time.
Ameren		None
AESO		The ones we are aware of have been noted in the responses previous questions.
Response: Thank you for your comments..		
Duke Energy		None
Hydro-Québec TransEnergie (HQT)		Yes, we have a modification to propose to the Applicability section which list different value for diffferent Region or Interconnection.We propose that the two paragraphs in Applicability 4.1.1.1 be modified to: Each unit (including synchronous condensers) 50 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years. Each unit (including synchronous condensers) 20 MVA within a plant 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.
Response: Thank you for your comments. The SDT believes that the industry has overwhelmingly accepted the model verification 80% threshold which would result based on the draft language of the Applicability section.		
Independent Electricity System Operator		Variances are already provided in the Applicability Section (for the 3 Interconnections).

Organization	Yes or No	Question 11 Regional Variance and Comment
Response: Thank you for your comment.		
US Bureau of Reclamation		WECC has developed a comprehensive regional machine testing and model validation policy that includes dynamic models for all the major generation components and the applicability thresholds are much more strict than those proposed in the draft MOD-026-1.
Response: Thank you for your comments. The SDT understands WECC is not planning to submit a regional variance at this time.		

12. If you are aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

Summary Consideration:

No substantial conflicts were identified by industry.

Organization	Yes or No	Question 12 Conflict
Northeast Power Coordinating Council		None.
Kansas City Power & Light		Not aware of any conflicts.
MRO NERC Standards Review Subcommittee		No
IRC Standards Review Committee		None
Luminant Power		NA
Constellation Power Generation & Constellation Nuclear		None.
Consumers Energy Company		N/A
American Electric Power		CONFLICT: The added expense posed by the requirements of this standard must be sought through tariff changes with applicable regulatory authorities. COMMENTS: A strong cost-benefit analysis is required to receive the necessary cost recovery.
Response: Thank you for your comment. The SDT believes that the Applicability section has been structured so that industry cost is minimized, which the majority of industry responders agree.		
Manitoba Hydro		none
Progress Energy, Inc.		No.
Dynegy		None at this time.

Organization	Yes or No	Question 12 Conflict
Ameren		None
Duke Energy		None
Independent Electricity System Operator		None

13. If you have any other questions or concerns with the proposed standard that have not been addressed in responding to the questions above, please provide them here.

Summary Consideration:

Based in part on industry comments received to this question, the following modifications to the proposed standard have been made by the SDT. (note: some of these issues and listed modifications are addressed by other consideration of comments questions):

1) Use the term “excitation control system” as appropriate to be consistent with terminology used in IEEE 421.1 (includes the voltage regulator, exciter, and generator).

2) Clarify the new Applicability section (including footnotes) to indicate that only units with 5% or less capacity factor are exempt with status reaffirmed every ten years. including new requirement (reference Requirement R5 in the revised standard) providing a mechanism for low capacity factor units identified by the Planning Coordinator to require model verification.

3) Modify the Applicability section to include “same point of interconnection” language.

4) Clarify the SDT position regarding the potential reliability gap with wind generation. Based on industry comments and concerns expressed by NERC staff, the SDT has expanded the Applicability section to include a large percentage of small units which would include variable energy resources such as wind generation.

5) Requirements have been restructured for clarity in the second posting of the standard.

Organization	Question 13 Comments
NERC Event Analysis & Information Exchange staff	It seems that having an overall generator testing standard in place on the dynamic parameters listed in MOD-013 would be a prerequisite for an excitation testing standard.
Response: Thank you for your comment. The SDT agrees an accurate representation of the generator system is essential for obtaining a match between simulated and measured results however, the SDT believes that a match between simulation and measured results for the excitation system model validation indicates that the generator and excitation control system models are both representative of the equipment. If the results do not match, then the SDT agrees further testing may be required to obtain appropriate generator parameters. To prevent further delays with developing the MOD-026 standard, the SDT will not consider a generator verification standard as part of the exciter verification standard development process.	
Southwest Power Pool Generation Working	The SPP Generation Working Group members have several concerns related to this standard. The skill-set required to perform these tests do not currently exist among Generator Owners and there is a great concern that the limited subset of consultants that will be able to perform this

Organization	Question 13 Comments
Group	verification will not be able to complete these tasks within the suggested ten year period. Given the limited subset of parties that will perform these tests, the cost will be onerous on the Generator Owners while not providing significant benefits.SPP Generation Working Group members do not know of any issue that these enhanced requirements would have helped avoid and therefore see little value, given the potentially high cost, to these expanded requirements. SPP Generation Working Group members generally oppose the current version of this standard.
Response: Thank you for your comments. Field testing confirmed that verification of excitation system models does result in higher quality dynamics data that will result in more accurate dynamic simulations that can define security limits so the SDT believes that these requirements positively contribute to BES reliability. Field test also indicated there is a cost to perform excitation system model verification so the SDT believes that the NERC Compliance Registry should not be referenced in the Applicability section. Instead, the Applicability section will identify a subset of units defined by the Compliance Registry which are expected to have significant impact on BES reliability.	
SERC Dynamics Review Subcommittee (DRS)	Requirement 1 says testing should occur "for new or existing units within 180 days of commerical operation". We believe the testing should be done before commerical operation.
Response: Thank you for your comments. The SDT notes some areas have existing grid code that require excitation control system model verification before commercial operation occurs. The SDT recognizes transmission entities can adopt more stringent requirements.	
Dominion	The SDT should define exactly what the "excitation model" means. At a minimum it should include the AVR, exciter, PSS (if installed) and voltage compensator (if installed). The current document appears to imply that the minimum and maximum excitation limiters (if installed) are not part of the "excitation model." 2. We are concerned that, in order to meet this standard, applicable entities may have to share data and software that may be proprietary and which may vary depending upon vendor(s) selected by the Transmission Planner. R2 states that models cannot be confidential or proprietary. 3. We believe that applicabilty section should be modified so that it only includes entity(ies) defined in the NERC Functional Model. At 4.1.1 it states Generator Operators of generating facilities: We believe it should state Generator Owner (the term used in functional model). a. We can support 4.1.1.1 if the language is revised to read With generators that are connected to Eastern or Quebec Interconnections with the following characteristics 4. The requirement R2 should be restated to read: The Transmission Planner shall provide the Generator Owner a set of model data sheets for the standard (as opposed to acceptable)excitation system models for use in dynamic simulation software, with each data sheet including the excitation system model block diagram structure and data requirements, within 30 calendar days of a request from the Generator Owner. If the excitation system characteristic is such that it cannot be represented by one of the Standard models, the Generator Owner shall be obligated to have a user-written model developed and made it available to Transmission Planner for use in the dynamic simulation software used by the Transmission Planner.
Response: Thank you for your comments. After reviewing IEEE 421.1, the SDT believes that the term “excitation control system model” is more appropriate to use in the standard then “excitation system model.” This is because the term “excitation control system model” references the entire closed loop system including the synchronous machine. The SDT has adopted this language in the second draft of the standard; which also includes excitation system limiters that are part of the exciter. This language does not include excitation protective devices that are independent of the excitation system. Independent protective devices will be addressed in the initial	

Organization	Question 13 Comments
posting of the draft standard PRC-019. Regarding your second comment, the SDT believes proprietary models cannot be allowed and that the static block diagram must be selected from the list of models provided by the Transmission Planner. Regarding your third comment on the Applicability section, the SDT believes that the combination of the Functional Model entity and the criteria statement of unit size per interconnection is appropriate. The SDT recognizes that user written models are sometimes necessary however this is not desirable. The SDT purposely changed Requirement language such that the Generator Owner would have to propose a user written model to its Transmission Planner for incorporation on the acceptable list of model data sheets.	
Kansas City Power & Light	Where specific codes and standards are referenced as either the technical basis for, or an acceptable means to comply with the NERC requirements, such as IEEE 421 referenced directly in Draft 1 of MOD-026-1, or IEEE 1110 and IEEE 415, please clarify these are references only and the content of these references in no way add to the requirements proposed here.
Response: Thank you for your comments. Please note that the References section contains the disclaimer: "The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.".	
FirstEnergy	1. In R1.4 it should be clear that the unit is achieving the 5% capacity factor for the first time over the last three calendar years.2. R9 states that the Generator Operator shall make documentation demonstrating the excitation system model's response is appropriate available for inspection and technical review 'to' the RC, TOP, and PC. The term "make available" is vague and should be revised to provide more specifics as to how this information is to be made available for inspection and technical review 'by' the RC, TOP, and PC.3. The term "Capacity Factor" is not NERC defined and is shown as capitalized in the standard. We suggest the team develop either a standard-specific or NERC Glossary definition. The following is a suggestion: "Capacity Factor (expressed as a percent) - The net actual energy generation (MW-hours) divided by the product of the period (hours) and the net maximum nameplate rating (MW)."4. Sec. 4 Applicability - We do not agree with the criteria proposed for the Eastern Interconnection and believe it may leave out some important or critical units. Also, it may be better to just have one criteria throughout the interconnections. We recommend the SDT consider using the NERC Registry Criteria for all units based on plant aggregate of 75 MVA or greater and unit size of 20 MVA or greater.5. Per Question 10 above, why wouldn't the Regional Entity procedures or guidelines be allowable for compliance after the first 5 years? [Note: It is assumed that the SDT intended to say "first" 5 years, not "last" five years in the description after Box 3 of that question]
Response: Thank you for your comments. Based on industry comments, the second draft of the standard has been modified to make clear in the Applicability section (including related footnote) that only the capacity factor three year average must be checked once every 10 years . Note that there are other mechanisms in the standard that could result in low capacity factor units being verified (refer to Requirement R6, reference Requirement R2 in the revised standard). Regarding the term "make …available", the SDT has reworded the language, now contained in Requirement R2 that does away with the term "make…available". The SDT agrees that the term "capacity factor" was incorrectly capitalized in the draft standard and has been corrected in the second draft. The SDT did consider using the NERC Registry Criteria, but the SDT recognized that the excitation system models and model data are already collected through the processes identified in standards MOD-012 and MOD-013 and, with few exceptions, already establish a quality dynamics database. Therefore, based in part on recent entity experience with verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. The vast majority of industry responders agree with t this approach (reference Question 8). Also note that the second draft of the standard includes a process for selecting additional units for excitation control system model verification. Regarding the implementation plan, the SDT has clarified the language for models already verified by Regional Procedures	

Organization	Question 13 Comments
through year 5.	
Entergy Fossil Operations	In Requirement R5 in the event that a model is determined to be unusable and is returned to the Generator Owner for further action the transmission operator should be required to also provide the steps he has taken to exercise due diligence in the integration of the exciter system model into the over all model. This should take the form of review of data inserted against data provided, model name reviewed against model provided, etc.The transmission operator should also provide the Generator operator witih text copy of the actual exciter and generator portion of the overall model.
Response: Thank you for your comments. The SDT believes that both parties have a vested interest in resolving issues leading to unusable models. As such, the SDT does not believe that specific details regarding the exchange of information during entity collaboration needs to be specified in the Requirements.	
IRC Standards Review Committee	We offer the following comments: a. The proposed standard lacks clarity needed for implementation as a mandatory standard. Specifically, there are different views in the industry as to what exactly is a model data sheet. Is it the block diagram of the excitation system's control system and parameters, or is it the simulation software's model sheet such as, for example, a vendor's data sheet for a specific type of exciters which it is capable of modeling in its simulation software, say, IEEEST, EXST1, or whatever name it may be, etc. We suggest clearer language be used to more specifically describe what a model data sheet means. Also, verification is subject to interpretation: is it a comparison of the expected input/output response of the excitation system versus actual response, or the expected performance of the generators when a computer simulation is conducted? b. A number of points/bullets in several requirements need to be performed to meet the intent of the main requirements, even though some of them ar e mutually exclusive (i.e. either/or). As such, they should be labeled sub-requirements. These include:- R1: Points number 1 and 2- R4: Points number 1 to 5- R11: All bullets- R10: Both bullets- R12: The last 2 bulletsc. R5: The condition that "if the excitation system model is usable" needs further elaboration. Evidence showing either Conditions (1) or (2) may suggest that either the model incorrectly reflects the excitation system or the excitation system itself, despite being modeled correctly, gives rise to the observed condition. The word "usable" thus needs to be expanded to more properly indicate whether the data is not usable or the excitation system is no useable. d. R6: The above comment on R5 also applies to R6.
Response: Thank you for your comments. The SDT has modified the language (reference Requirement R1 in the revised standard) to contain the phrase "software manufacturer's dynamic excitation control system or plant volt/var control function system model library block diagrams and/or data sheets". Verification specified in Requirement R8 (reference Requirement R2 of the revised standard), is achieved when it is shown that the excitation system model's response (i.e., predicted response utilizing the model in a dynamic simulation) matches the recorded response for a voltage excursion at the generator terminals. The structure of Requirements in the first draft was envisioned to make it easier to construct Measures, Violation Severity Levels etc.. Requirement number and bullet lists conform with standard development protocol. Specifically, a number list indicates all requirement list actions must be performed by the entity whereas the bullet list indicates the entity selects which of the requirement list actions is appropriate to perform. Action for determining if the model is useable or not should not be confused with model verification for ensuring the model response matches the actual equipment response. A model is considered "useable" if it does not cause angle drift during a no-disturbance simulation or does not causes poor or undamped oscillations in a dynamic simulation of a mild system fault disturbance. Requirement R5 (reference Requirement R6 in the revised standard) does not reference the ability of the model to accurately predict the expected actual response of the equipment.	

Organization	Question 13 Comments
FEUS	The excitation models as currently required are comprised of testing and data collection to determine the variables for the model parameters. How does additional testing, over and above what was done to construct the model, accomplish anything and how would it be any different than original testing to complete the model?
Response: Thank you for your comments. The SDT assumes your comments refer to the periodicity for verification. The SDT believes that a 10 year timeframe is a reasonable re-verification requirement. This timeframe is supported by an overwhelming majority of industry comments.	
Exelon Corporation	The proposed standard and comment form presuppose the generator owners have the expertise necessary to model and simulate the excitiation systems on the units they own. They do not in most cases. Software requirements need to be considered. Not all transmission planners use the same software for dynamic simulations. A single generation owner may have units in multiple regions involving different transmission planners and would have to provide models for more than one simulation program. The standard needs to allow the Transmission Planner/Operator/Owner to provide expertise to the generator owner. The comment form and the WebEx meetings are more specific regarding software simulations than what is specified in the draft standard. The software simulations should be specified in more detail in the standard.
Response: Thank you for your comments. The SDT agrees that a cooperative effort is required among NERC functional model entities in order to develop a robust excitation system model. As mandated by Reliability Standard process, only one entity is assigned responsibility for excitation system model verification. The SDT believes it has incorporated into the draft standard all necessary interactions with other functional model entities required for ensuring model verification success. The Generator Owner is responsible for model verification. It is anticipated that the Generator Owner could delegate model verification activities to other entities by contractual agreement as appropriate. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. The standard cannot list specific commercial software options.	
Constellation Power Generation & Constellation Nuclear	The standard needs to clarify what verification of excitation system model entails; does this involve testing of excitation parameters? Online or offline. On line testing of excitation parameters will present an unacceptable tripping risk to nuclear units.Recommend nuclear units be exempt from excitation system model verification if it involves online testing.
Response: Thank you for your comments. Online testing is not required. The SDT believes it is best to leave the technical details of model verification to the experts. The draft standard simply requires demonstration that a recorded excitation control system response matches the model predicted response. The recorded excitation control system response could be obtained by ambient monitoring or an open circuit step in voltage test, neither of which is an online test. In part because online testing is not required, the SDT does not foresee a reliability need to exempt nuclear units from model verification.	
Southern Company	Paragraph 4.1.1.1 3rd Section: The plant criteria should be assessed on a switchyard basis instead of all inclusive. For example: 5 unit station with 4 units > 100 MVA each connected at 500 kV and one unit <50 MVA connected at 115 kV. Why do I need to do the small unit? Paragraph R1.2: See discussion in question 3 above regarding the criterion of 'sited at the same physical location and MVA ratings.' We see

Organization	Question 13 Comments
	no need for these restrictions. Paragraph R7: A third option is to do more testing/technical assessment with a longer time allowed (>90 days) should be included. Paragraph R8: The last part of this requirement is unclear: 'within 90 calender days. verification.' Change the wording from 90 calendar days of competion to 90 calendar days after completion. The requirement will than read, " The Generator Operator shall provide to the Transmission Planner documentation demonstrating that the excitation's system model's response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) within 90 calendar days after completion of the excitation system model verification ."Paragraph R12: The second and third bullets should be combined to cover any DCS/AVR inter-actions.
Response: Thank you for your comments. The concern expressed in your first comment has been addressed in the 2nd draft of the standard by modifying the language in the Applicability section to make it clear that the thresholds identified are for units interconnected to the same transmission voltage level bus. For your second comment, please reference Question 3. Regarding your third comment, the second draft of the standard allows for the verified model and documentation to be provided to the Transmission Planner within one year from the date that the recorded voltage excursion used for model verification was collected (reference Requirement R2 in the draft standard, and the Periodicity Attachment). The SDT agrees with recommended modifications to Requirement R8 (reference Requirement R2, Part 2.1 in the revised standard) language and has made the modification. Regarding the last comment, the two DCS activities referenced could be combined however the SDT thought maintaining these as separate activities improved clarity.	
E.ON U.S.	E.ON U.S. believes that the staggered implementation time tables for the various standard requirements could needlessly complicate initial compliance efforts. E ON U.S. requests that the SDT review these deadlines and standardize using the most lenient implementation period set forth in the second draft. E.ON U.S. recommends that the standard explicitly state in the purpose statement that voltage regulators be included in excitation system models. Voltage regulators are explicitly mentioned in R4.3 and R12.E.ON U.S. recommends that study data inputs and results only be made publicly available pursuant to Requirement 2. Depending on arrangements with vendors, actual model configuration may be proprietary and require confidential disclosure arrangements
Response: Thank you for your comments. Not requiring excitation control system model verification for 10 years is not considered acceptable by the SDT. Note that Requirement R2 (reference Requirement R2, Part 2.1 in the revised standard) indicates only models on the list of acceptable excitation control system models can be utilized and it is not expected that any of these acceptable models will be confidential or proprietary given this would unduly disrupt the dynamic data base process which is necessary for Interconnection wide security analysis. After reviewing IEEE 421.1, the SDT believes that the term “excitation control system model” is more appropriate to use in the standard then “excitation system model.” This is because the term “excitation control system model” references the entire closed loop system including the synchronous machine. The SDT has adopted this language in the second draft of the standard; which also includes excitation system limiters that are part of the exciter.	
Consumers Energy Company	It is our opinion that the SDT made a fundamental error in assigning the modeling to an entity that doesn't need the results of the model. To correct this error, this Standard needs very significant revision. As it stands, the Draft Standard imposes irrational requirements upon the Generator Operator.
Response: Thank you for your comments. The SDT understands that no matter who is assigned responsibility in the proposed continent-wide standard, it would potentially change the current business model of the functional entity. The majority of the SDT believes that a generation entity should have both final excitation system model responsibility and authority, Based on the majority of industry comments and guidance from the FMWG, the second draft of the standard assigns responsibility to	

Organization	Question 13 Comments
the Generator Owner. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. Note that existing business practices that utilize Transmission Planners can still exist; the only difference is that the Generator Owner would be ultimately responsible for the excitation system model verification from a compliance perspective. Also, the SDT is proposing an Implementation Plan to allow the Generator Owner time to develop in-house expertise to perform model verification if they do not desire to hire consultants.	
Wisconsin Public Service	At plants with 200MW or higher capacity, it is unreasonable to assume multiple units of 20MW to malfunction simultaneously. Therefore, applying the standard to each unit of >/= 20MW if these are at the same contiguous plant of combined capacity of 200MW is placing unreasonable burden on owners of small generators. One must reason that, in the contest of the whole eastern interconnect, comprising a total capacity of 600,000MVA and higher, individual generators of less than 100MVA would not impact the system to any significant degree except for very localized regions.
Response: Thank you for your comments. Please note that the Applicability section is based on MVA instead of MW. The MVA threshold specified are less stringent than the NERC Compliance Registry and appears to represent an appropriate threshold based on industry responses received.	
American Electric Power	(1) The added expense to fulfill the requirements of this standard where such model verification is not generally being done could be high. Since this is a new imposition on the industry in that required excitation model verification has never before been imposed in many areas, this leads to the question of cost versus reliability benefit of what is being proposed. We request that the SDT please comment more on the cost vs. reliability benefits. (2) With respect to R2, we suggest that it be revised and expanded as follows: "The Transmission Planner shall provide the Generator Operator a set of model data sheets for the acceptable excitation system models (models cannot be confidential or proprietary) for use in dynamic simulation software, with each data sheet including the excitation system model block diagram structure and data requirements and a system dynamics model, within 30 calendar days of a request from the Generator Operator." (3) With respect to R6, revise and expand the last sentence as follows: "If the TP determines the excitation system model is not useable, the TP shall provide the Generator Operator with a description of the problem and any relevant details, including the system dynamics case used in the evaluation." (4) With respect to last sentence in R9, revise and expand as follows, "?. after the receipt of a request that includes the measured data following a system disturbance and a suitable system dynamics case associated with the system disturbance.
Response: Thank you for your comments. Note that excitation control system model verification is part of the original NERC Planning Standards. Also, a major conclusion of the standard MOD-026 field testing performed for Phase III-IV is that verification of excitation models did provide a reliability benefit. Since the software used by a Generator Owner to perform model verification activities does not have to be a full dynamic simulation software package, the SDT does not see a need to add additional requirements for the Transmission Planner to provide system dynamic cases to the Generator Owner. However, if such cases are needed to resolve a model verification issues, then it would be beneficial and in the best interest of the Transmission Planner to provide dynamic cases to the Generator Owner.	

Organization	Question 13 Comments
Arizona Public Service Co.	The standard appears to be too unnecessary complicated. We have the following suggestion for simplification. 1)Requirements R1, R4, R11 and R12 are the only reliability related requirements and should be kept. 2)R8 is part of providing data and should be a part of R4 3)All other requirements are simply indicate process and do not belong in the standard. They should be part of a white paper on the subject or in an appendix.
Response: Thank you for your comments. The SDT combined several requirements in an effort to simplify the standard and improve clarity.	
Wisconsin Electric	Please consider the use of offline measurement of generator excitation response as a possible means to comply.
Response: Thank you for your comment. An open circuit step in voltage test, which is a test that is performed before the generator is synchronized to the transmission system, is acceptable. Also, note that the SDT drafted a Standard that concentrates on “stating what is required” but not “stating how to accomplish what is required”. Any technique that shows the excitation system model’s response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) is acceptable.	
Manitoba Hydro	The MOD-026 Standard uses different terminiology in two different places. In requirement 4, the fourth bullet uses the term Reactive compensation and in Requirement 12, the fourth bullet uses impedance compensator. Either term is fine to use, but should be consistent throughout the standard.
Response: Thank you for your comments. The SDT believes it has revised the standard such that the use of the term “compensation” is appropriate where utilized. The SDT would appreciate your feedback verifying that this has been accomplished.	
Progress Energy, Inc.	Requirement 1 Item 1) should be clarified to state that "new equipment commissioning date" applies to modifications of existing units. Requirement numbering for R1, R4, R5, R7-12 needs to be revised to conform to proper format.
Response: Thank you for your comments. Formatting for the second draft of the standard has been modified significantly to minimize confusion. The periodicity requirements have been transferred into a separate Attachment to avoid confusion over verification timing requirements.	
Ameren	(1) Requirement 1 states that testing should occur "for new or existing units within 180 days of commerical operation". We believe the testing for the new units should be done before commerical operation. (2) In Requirement R2, the Transmission Planner would not necessarily have any idea which model would best fit the installed equipment. The only workable way to comply with this requirement is for the Transmission Planner to give the Generator Operator the data sheets for the entire library of available exciter models. The Generator Operator would then need to determine which of these models would provide the best fit for the excitation system equipment to be modeled. We believe that this requirement should recognize that deriving "acceptable" model

Organization	Question 13 Comments
	for a specific excitation system is a cooperative effort between manufacturer, GO/GOP, and TP. (3) While wind generators would generally fall below the unit size thresholds as specified in Requirement 4.1.1, it would be very helpful in conducting dynamic simulations involving wind generators if their dynamic representations would be fit into one of the standard library models. (4) There are several 90 day periods mentioned in the Requirements. It might be helpful to be more specific as to which 90 day interval is meant. For example, Requirement R8 should read something like "?within 90 days of completion of the excitation system model verification as specified in Rx." (5) This comment is in reference to MOD-026-1, R.12. We believe that Digital Control Systems do not effect excitation systems models. Therefore we suggest removing requirements associated with Digital Control Systems.

Response: Thank you for your comments. The SDT notes some areas have existing grid code that require excitation control system model verification before commercial operation occurs. The SDT recognizes transmission entities can adopt more stringent requirements. The SDT believes that the process described in Item 2 is desirable and expects involved entities to follow this process.

Regarding Item 3: The MVA thresholds in the Applicability section of the first posting of MOD-026 resulted in wind powered units not being subject to this standard because no single wind unit is rated greater than 20 MVA. However, there is an increasing number of wind farms with significantly larger aggregate MVA. As such, their impact on the reliability of the Bulk Electric System cannot be ignored – otherwise, a reliability gap would be created.

Therefore, based on your comments and other industry comments, the SDT discussed the possibility of requiring verification of dynamic models that represent the aggregate of numerous small units and any necessary auxiliary equipment as required due to the technology of the small units. This could include plant dynamic voltage control and reactive support of all the units and auxiliary equipment (such as individual WTG response, plant-wide volt/var controller response, and response from separate volt/var regulation devices contained in the plant, such as SVC/STATCOM/Synchronous Condenser) contained in any technology generation plant, including a wind farm (plant), that exceeds appropriate aggregate nameplate MVA threshold.

There are dynamic models that adequately replicate wind unit performance for some wind units today. However, there are many existing wind units for which there are no publicly available models supplied by the Original Equipment Manufacturer. Generic wind models (i.e., type I, II, III and IV) are in various stages of development. Also, there are ongoing efforts involving Regional Entities and manufactures to close any large gaps that may exist in current generic models. Given that there will be significant time between now and the time that this standard could be approved by FERC, it is expected that generic wind farm (plant) models will reach an appropriate state of maturity for establishing boundary conditions in Bulk System Studies. In order to mitigate the reliability gap, the Applicability section will be expanded in the second posting of the standard to include significant MVA percentage of all generation for all technologies.

Regarding the comment indicating that the 90 day periods referenced in the previous posting of the standard did not always clearly communicate schedule expectations, the SDT has moved required model verification periodicity information into a stand-alone Attachment attached to the standard for making it clear that model verification periodicity would occur at least every 10 years. The SDT has also ensured that other timing references in the second draft of the standard are clearly understood.

Finally, several SDT team members have observed that DCS changes can affect excitation system performance within the timing cycle of the excitation system model...

Organization	Question 13 Comments
AESO	The AESO agrees with the SRC ISO/RTO comments. We would also like to empahsize the importance of complete unit testing as noted in our response to Question 4.
Response: Thank you for your comments. The SDT was unable to identify the other comment mentioned in Question 4. Please refer to that comment to review the SDT response provided.	
Duke Energy	Section 4.1Should the standard be revised to include small units that are part of an aggregate 200 MW facility? For example : wind farms with many 1.5 MW turbines Recommend changing R5.1) to read The model initializes properly and a no-disturbance simulation contains no transients The second bullet of R7 allows an unusable model to not be corrected. Unless the point is that the unit would be out of compliance, this seems to negate requiring verification. Recommend the team to consider that all units that meet the applicability have usable models. For R12, rather than only listing the high level components, we recommend the team also note that other generator components such as a new excitation system power transformer (not a like-for-like changeout) can have an impact on aspects of the model.
Response: The MVA thresholds in the Applicability section of the first posting of MOD-026 resulted in wind powered units not being subject to this standard because no single wind unit is rated greater than 20 MVA. However, there is an increasing number of wind farms with significantly larger aggregate MVA. As such, their impact on the reliability of the Bulk Electric System cannot be ignored – otherwise, a reliability gap would be created. Therefore, based on your comments and other industry comments, the SDT discussed the possibility of requiring verification of dynamic models that represent the aggregate of numerous small units and any necessary auxiliary equipment as required due to the technology of the small units. This could include plant dynamic voltage control and reactive support of all the units and auxiliary equipment (such as individual WTG response, plant-wide volt/var controller response, and response from separate volt/var regulation devices contained in the plant, such as SVC/STATCOM/Synchronous Condenser) contained in any technology generation plant, including a wind farm (plant), that exceeds appropriate aggregate nameplate MVA threshold. There are dynamic models that adequately replicate wind unit performance for some wind units today. However, there are many existing wind units for which there are no publicly available models supplied by the Original Equipment Manufacturer. Generic wind models (i.e., type I, II, III and IV) are in various stages of development. Also, there are ongoing efforts involving Regional Entities and manufactures to close any large gaps that may exist in current generic models. Given that there will be significant time between now and the time that this standard could be approved by FERC, it is expected that generic wind farm (plant) models will reach an appropriate state of maturity for establishing boundary conditions in Bulk System Studies. In order to mitigate the reliability gap, the Applicability section will be expanded in the second posting of the standard to include significant MVA percentage of all generation for all technologies. The SDT agrees with the comment to add the phrase "model initializes properly" and has included this language in the second draft of the standard. Regarding Requirement R12 (reference Requirement R2 in the revised standard), the bullet point examples are not-inclusive (given the main requirement includes the phrase: "includes but are not limited to"). The SDT aimed to include examples likely to occur and while the example provided is valid, the SDT does not believe it is one of the most likely scenarios to occur.	

Organization	Question 13 Comments
Xcel Energy	Capacity Factor needs to be defined.
Response: Thank you for your comments. In the second draft standard, capacity factor is not capitalized and has been clarified in the Applicability section (also refer to the footnote).	
Independent Electricity System Operator	We offer the following comments: a. A number of points/bullets in several requirements need to be performed to meet the intent of the main requirements, even though some of them are mutually exclusive (i.e. either/or). As such, they should be labeled subrequirements. These include:- R1: Points number 1 and 2- R4: Points number 1 to 5- R11: All bullets- R10: Both bullets- R12: The last 2 bullets b. R5: The condition that "if the excitation system model is useable" needs further elaboration. Evidence showing either Conditions (1) or (2) may suggest that either the model incorrectly reflects the excitation system or the excitation system itself, despite being modeled correctly, gives rise to the observed condition. The word "useable" thus needs to be expanded to more properly indicate whether the data is not useable or the excitation system is not useable. c. R6: The above comment on R5 also applies to R6.
Response: Thank you for your comments. Regarding the organization recommendations provided, Requirement R1 details have been moved to a stand alone periodicity Attachment attached to the standard and the SDT significantly re-formatted the standard to reduce and simplify requirements so that entities will have a clear understanding of how to be compliant. The Violation Severity Levels will define treatment of these requirements for compliance. Additionally, there has been significant effort to streamline the draft standard. The SDT believes the new format is robust, fair, and will result in reasonable VRF and VSL determination. Regarding the use of the term "usability", the second draft of the standard identifies benchmarks which determine if the model is useable or not. As recommended by industry, the requirement that the model must initialize properly has been added to the standard. The SDT believes that the criteria defining model usability has been adequately specified.	
American Transmission Company	ATC disagrees with portions of Requirement 2 which stipulates that the TP shall provide the excitation system model block diagram (block diagram) structure and data requirements. Many manufactures currently make their block diagrams and data requirements available to the GO/GOP. In addition, IEEE Standard Definitions for Excitation System for Synchronous Machines allows a GO/GOP to identify the type of exciter and/or PSS installed on their units along with the corresponding block diagrams and data requirements. Recommend that the words following "dynamic simulation software." be deleted.
Response: Thank you for your comments. The SDT believes that it is critical for the Transmission Planner to provide the Generator Operator block diagram structures and data requirements that can be represented in the Transmission Planner dynamic simulation software package. Otherwise, the Generator Operator could perform verification with a model that would not run in the Transmission Planner dynamic simulation software package.	
US Bureau of Reclamation	We see a blurring of the requirements between Standards MOD-012-0-Dynamics Data for Transmission System Modeling and Simulation; MOD-013-0- RRO Dynamics Data Requirements and Reporting Procedures; and the draft of MOD-026-1 - Verification of Models and Data for Generator Excitation System Functions. If entities are in compliance with MOD-012-0 and MOD-013 we see no additional enhancement to

Organization	Question 13 Comments
	reliability by the addition of this draft standard.
Response: Thank you for your comments. Standards MOD-012 and MOD-013 state requirements for submission of data, including excitation control system model data. Standard MOD-026 state requirements for the verification of that data (i.e., that model and the model data adequately predict the expected actual performance of the equipment).	
Luminant Power	NA
Dynegy	None at this time.
Northeast Power Coordinating Council	No.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR authorized by Standards Committee for development as a reliability standard July 12, 2007.

Standard Drafting Team appointed by Standards Committee September 11, 2007.

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed revision to this standard and includes requirements without violation risk factors, time horizons, measures or Violation Severity Levels. This first posting is for a 30-day comment period from January 6 through February 5, 2010.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and second version draft revision of standard.	June 2010
2. Post response to comments and request authorization to ballot the revised standard.	September 2010
3. Conduct initial ballot.	October 2010
4. Post response to comments.	November 2010
5. Conduct recirculation ballot.	December 2010
6. BOT adoption.	February 2011
7. File with regulatory authorities.	March 2011

A. Introduction

1. **Title:** **Verification and Data Reporting of Generator Real Power Capability**

2. **Number:** **MOD-024-2**

3. **Purpose:** To ensure that planning entities have accurate generator Real Power capability modeling data used in system planning studies.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Generator Owner

   4.1.2 Planning Coordinator

   4.1.3 Resource Planner

   4.2 Facilities:

   4.2.1 Generating Facilities connected at the point of interconnection at 100 kV or above, containing an individual generating unit greater than 20 MVA (individual gross nameplate rating)

   4.2.2 Generating plants/Facilities connected at the point of interconnection at 100 kV or above, containing greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3 Variable energy units such as wind generators, solar, and run of river hydro are exempt from the requirements of this Standard.

5. **Effective Date:** All requirements of MOD-024-2 become effective the first day of the first calendar quarter six months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter six months after Board of Trustees adoption.

   Verification requirements in this standard cover the summer and winter peak periods; the compliance monitoring:

   - for units to be verified annually per MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability, section number 4, will begin 30 calendar days following the first summer or winter peak period that begins at least 60 calendar days following the effective date.
   - for units to be verified every five years per MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability, section number 4, will begin five years after the compliance implementation date for annual units.

B. Requirements

R1. Each Generator Owner shall verify the summer and winter Real Power generating capability for each of its units in accordance with MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability and record and submit the information via MOD-024-2 Attachment 2 - One-line Diagram, Table and Summary for Verification Information Reporting.

[Violation Risk Factor: TBD] [Time Horizon: TBD]

R2. Each Resource Planner and Planning Coordinator that seeks verified generating unit Real Power capability data shall provide each Generator Owner:

- the desired temperature to which the data is to be adjusted.
- <u>and</u> the reporting schedule consistent with section number 4 of the MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability.

[Violation Risk Factor: TBD] [Time Horizon: TBD]

R3. Each Generator Owner shall report to its Resource Planner and Planning Coordinator any change in the gross Real Power generating capability of any unit that is:

- greater than 50 MW compared with the last verification submittal
- <u>and</u> expected to last more than six months

within 15 calendar days of the determination that the change in capability is expected to last more than 6 months.

[Violation Risk Factor: TBD] [Time Horizon: TBD]

C. Measures:

M1. Each Generator Owner has evidence that it performed the verification (such as a completed MOD-024-2 Attachment 2) and has evidence that it submitted the information (such as dated electronic mail messages or mail receipts) in accordance with Requirement R1.

M2. Each Resource Planner and each Planning Coordinator has evidence (such as dated electronic mail messages or mail receipts) that it provided each Generator Owner the desired temperature to which the verified Real Power generating capability is to be adjusted and the report schedule as specified in Requirement R2.

M3. Each Generator Owner has evidence (such as dated electronic mail messages or mail receipts) that it reported the amount of a change in a unit's gross Real Power capability as specified in Requirement R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority**

Regional Entity

1.2. **Compliance Monitoring Period and Reset Time Frame**

Not applicable

1.3. **Compliance Monitoring and Assessment Processes**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. **Additional Compliance Information**

2. **Violation Severity Levels (TBD)**

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.				
R2.				
R3				

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

MOD-024-2 Attachment 1 — Verification of Summer and Winter Generating Unit Capability

1. **Verify generating unit summer gross Real Power generating capability as follows:**

   1.1. For nuclear and fossil units, record data for one continuous hour of normal operation during the summer period.

   1.2. For hydro (other than run of river hydro) and pumped storage units, record data for one continuous hour of normal operation at any time during the year. Adjust the collected data to reflect forecasted reservoir levels or water flow conditions to reflect expected normal operation during the summer season.

   1.3. For units of less than 20 MVA that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group.

2. **Verify generating unit winter gross Real Power generating capability as follows:**

   2.1. For nuclear and fossil units, record data for one continuous hour of normal operation during the winter period.

   2.2. For hydro (other than run of river hydro) and pumped storage units, record data for one continuous hour of normal operation at any time during the year. Adjust the collected data to reflect forecasted reservoir levels or water flow conditions to reflect expected normal operation during the winter season.

   2.3. For units of less than 20 MVA that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group.

   2.4. Alternatively for any unit listed in 2.1, 2.2 or 2.3, by making a temperature correction to the most recent summer gross Real Power generating capability verification. The method used shall be indicated on the form used to record verified data.

3. Data recorded either during or associated with the summer and winter gross Real Power generating capability verification as specified in Number 1 and 2 of this Attachment shall include:

   3.1. The average value of the summer and winter gross Real Power generating capabilities over the verification period.

   3.2. The average ambient air temperature over the verification period.

   3.3. The date of the verification period, including start and end time

   3.4. The average megawatt values of the auxiliary Real Power loads and associated system connections, including nominal connection voltage, and an indication if such loads were metered or calculated.

      3.4.1. Include Real Power consumption by common auxiliary loads at a multiple unit facility (for example, coal-handling) by prorating the consumption among the appropriate units in the plant and assuming expected normal full load equipment operation of all units.

3.4.2. Provide an engineering estimate and associated calculations within 30 days of a request from the Resource Planner or Planning Coordinator for reported loads that were calculated since metering did not exist to measure such auxiliary load(s).

3.4.3. Include Generator Step-Up (GSU) and auxiliary transformers in MOD-024-2 Attachment 2 - One-line Diagram, Table and Summary for Verification Information Reporting.

3.4.4. Show Real Power flows assuming expected normal full load equipment operation of all units in Attachment 2.

3.4.5. Data adjusted according to the respective temperature specified by the Planning Coordinator and Resource Planner in accordance with requirement R2.

4. The periodicity for performing summer and winter Real Power generating capability verification is as follows:

4.1. For each generating unit with a generator maximum nameplate rating of greater than or equal to 75 MVA, annually.

4.2. For each generating unit with a generator maximum nameplate rating less than 75 MVA but greater than 20 MVA and with an average capacity factor over the last three years that is greater than five percent, annually.

4.3. For each individual generating units not included under 4.1 or 4.2 that is either greater than 20 MVA (gross nameplate rating) or is part of a generating plant/facility greater than 75 MVA (gross aggregate nameplate rating), either on an individual unit basis or as a group, verify at least once every five years.

4.4. Alternatively for multiple units installed at the same site where the units have identical designs, identical major components, identical significant control system settings and similar verified capabilities:

4.4.1. Verify approximately 20 percent of all such units annually with all units being verified over a five year period.

4.4.2. Verify at least one unit each year if fewer than five units meet the criteria in 4.4.

4.5. For a generating unit that does not run within the periodicity described in 4.1 through 4.4, verify the unit the next time the unit is run for one continuous hour of normal operation.

MOD-024-2 Attachment 2

One-line Diagram, Table and Summary for Verification Information Reporting

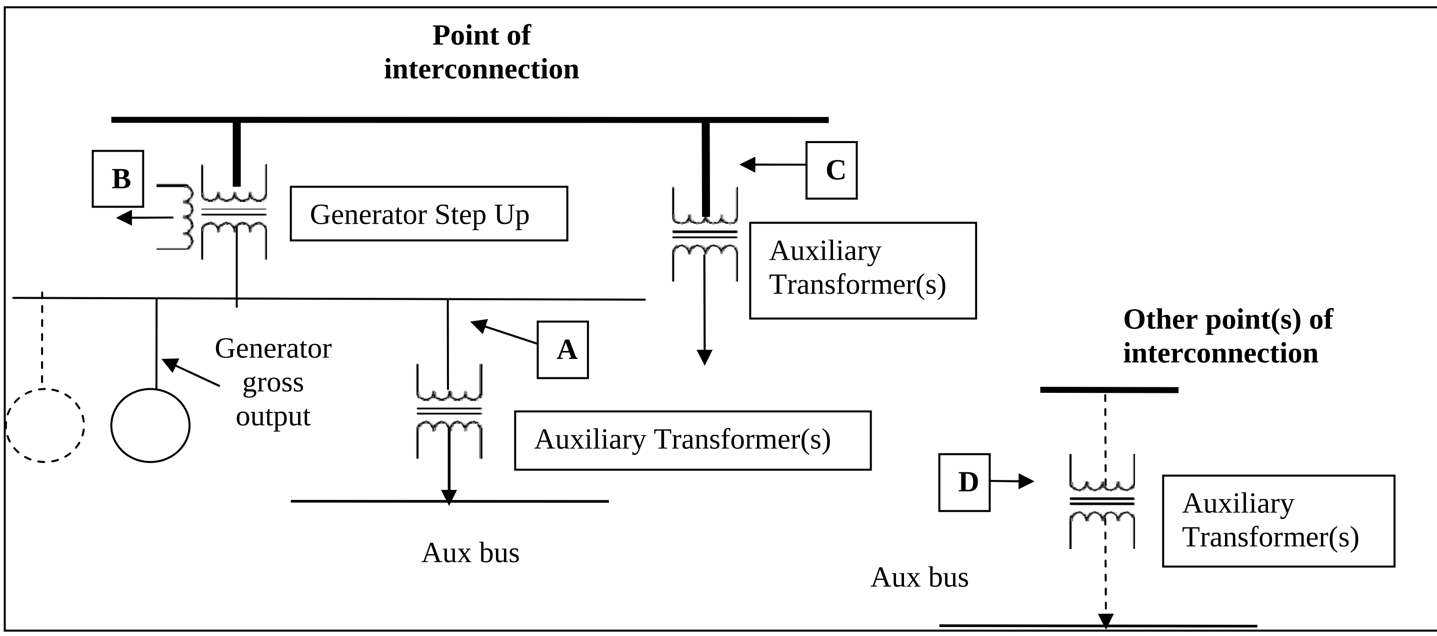
Note: If the configuration of the generation facility does not lend itself to the use of the diagram, tables or summaries for reporting the required information, changes may be made to this form provided that all required information (identified in MOD-024-Attachement 1) is reported.

Company ______________________________ Reported By (name)________________________

Plant __________________________________ Unit No___________

Date of Report _____________

Simplified one-line diagram showing plant auxiliary load connections and verification



data:

A: _________ kV _________MW (Sum multiple Auxiliary Transformers.)

☐ metered ☐ calculated

B: _________ kV _________MW (tertiary load, if any)

☐ metered ☐ calculated

C: _________ kV _________MW (Sum multiple Auxiliary Transformers.)

☐ metered ☐ calculated

D: _________ kV _________MW (If multiple points of interconnection describe these for accurate modeling; report points individually) (Sum multiple Auxiliary Transformers.)

☐ metered ☐ calculated

MOD-024-2 Attachment 2 (continued)

Summer Verification Data

(Provide data by unit or Facility as appropriate)

	Gross Real Power generating Capability (MW *)	Aux Power (MW *)	Gross Capability (MW *) minus Aux Power (MW *) equals Net Capability (MW *)
Recorded			
Adjusted			

* Note: Enter average values for the verification hour.

Summary of Summer Verification

- Date of Verification ______________________Verification Start Time; _____, Verification End Time ______

- Average ambient air temperature over verification period:

  Air temperature: _________°F

- The recorded MW values were adjusted for the following average temperature conditions:

  Air temperature: _________°F

MOD-024-2 Attachment 2 (continued)

Winter Verification Data

Provide data by unit or Facility as appropriate.

	Gross Real Power generating Capability (MW *)	Aux Power (MW *)	Gross Capability (MW *) minus Aux Power (MW *) equals Net Capability (MW *)
Recorded			
Adjusted			

* Note: Enter average values for the verification hour.

Check One:

☐ The winter data above is based on adjusted summer values

☐ The winter data above is based on tracking during a winter hour.

Comments:

Summary of Winter Verification

- Date of Verification[1] ___________Verification Start Time; ____________,

  Verification End Time ____________

- Average ambient air temperature over verification period:

  Air temperature: _________°F

- The recorded MW values were adjusted for the following average temperature conditions:

  Air temperature: _________°F

[1] If the winter verification is based on Summer data, provide only the date of the verification, not the start and end times.

Implementation Plan for MOD-024-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

MOD-024-2 — Verification and Data Reporting of Generator Real Power Capability

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. There are no new definitions in the proposed standard.

Compliance with Standard

The standard applies to Generator Owners, Planning Coordinators and Resource Planners.

Effective Date

All requirements of MOD-024-2 become effective the first day of the first calendar quarter six months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter six months after Board of Trustees adoption.

Verification requirements in this standard cover the summer and winter peak periods; the compliance monitoring:

- for units to be verified annually per MOD-024-2 Attachment 1 — Verification of Summer and Winter Generating Unit Capability, section number 4, will begin 30 calendar days following the first summer or winter peak period that begins at least 60 calendar days following the effective date.
- for units to be verified every five years per MOD-024-2 Attachment 1 — Verification of Summer and Winter Generating Unit Capability, section number 4, will begin five years after the compliance implementation date for annual units.

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RELIABILITY CORPORATION

Unofficial Comment Form for 1st Draft of MOD-024-2 Verification and Data Reporting of Generator Real Power — Project 2007-09 Generator Verification

Please DO NOT use this form. Please use the electronic form located at the link below to submit comments on the proposed 1st draft of MOD-024-2 Verification and Data Reporting of Generator Real Power developed by the standard drafting team as part of Project 2007-09 – Generator Verification. Comments must be submitted by **February 18, 2010**. If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at (860) 550-4157.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Background Information
The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024 — Verification of Generator Gross and Net Real Power Capability.
- MOD-025 — Verification of Generator Gross and Net Reactive Power Capability.

And four draft standards developed by the Phase III & IV SDT that were fielded tested by four Regions from mid 2006 through mid 2007.

- PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024 — Generator Performance During Frequency and Voltage Excursions
- MOD-026 —Verification of Models and Data for Generator Excitation System Functions
- MOD-027 — Verification of Generator Unit Frequency Response

Before beginning the detailed work of developing the standards, the SDT was presented the recently completed field test results by the participants from the four field test Regions. The SDT also reviewed how and to what extent the two NERC Board approved standards were used across all the Regions. As a result of its initial review, the SDT decided that it was appropriate to develop each standard separately and not attempt to combine or merge any of the standards. The SDT felt that Generator Owners and Generator Operators could possibly perform some of the requirements of more than one standard at a time but most likely would not.

Since each standard will be standing on its own merit, the SDT has decided to post for comment the standards on an "as ready" basis.

MOD-024-2 Verification and Data Reporting of Generator Real Power was developed with consideration to key issues stated in the SAR:

- Provide more details to the applicability section
- Replace the “fill in the blanks” requirements assigned to the Regional Reliability Organization with a set of “continent-wide” requirements
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization

1. Consider and address issues identified in FERC orders, including the modifications to MOD-024-1 as proposed in FERC Order 693
2. Consider and address issues identified during Phase III & IV field testing

The SDT first considered the “applicability” using the guidance set forth in the Functional Model. Initially, the SDT thought that although the Generator Owner may be responsible for the verified values of a unit’s capability, it is the Generator Operator that is the responsible entity to “operate” the unit in such a way as to obtain the required verification and any associated analysis – under the permission of the Generator Owner. The SDT felt that it is up to the Generator Owner and Generator Operator to work out any contractual arrangements associated with this relationship and not add requirements related to the Generator Owner providing approvals for the Generator Operator to perform such operations. After conferring with the Functional Model Working Group, the SDT was directed to change the applicability to Generator Owner based on roles and responsibilities assigned to the Generator Owner.

The SDT considered the extent of the facilities to be verified and how to reflect this in the “applicability”. Approximately 4% of the system capacity is connected at a voltage less than 100kV. The SDT concluded that 4% was not an impact on reliability, and did not require verification of units connected below 100kV. The SDT has proposed that this standard be consistent with the more general Compliance Registry Guidelines.

The SDT determined that attempting to verify the MW output of variable energy units is not material to the reliability of the Bulk Electric System since use of this data in simulations would not be appropriate, only partial operation would be expected for planning studies, and they are therefore exempted from the requirements of this standard.

During its review of current practices related to verification, it was evident that many entities that use generator real power capability data depend more heavily on data submitted in accordance with other and, in some areas, verification associated with regional requirements and required by markets. The SDT found that system planners across the continent have different views on how detailed the verification needs to be and what is the appropriate duration of the verification. This results from the fact that system planning studies reflect different conditions, such as range of temperatures, type of generators, extent of uncertainty included in the study, value of current verification on longer term studies, etc. As a result the SDT decided that a regimented verification was not appropriate and would not provide the “value added”. Instead the SDT has taken the approach that the Transmission Planner needs to communicate the conditions under which the Generator Owner is to provide verified values. The standard allows the Generator Owner to perform verification at any time during specific periods and use its experience and knowledge base of each unit to apply the appropriate adjustments to the verified values. This will help eliminate the need to run the unit through a potentially costly exercise to provide verified data that can be developed in a practical manner based on previous operation. This will also provide verified data consistent with the conditions the Transmission Planner expects to use them for.

In line with minimizing potentially unnecessary work by the Generator Owner and providing maximum benefit to the Transmission Planner, the SDT has developed a "diagram" guideline in the form of Attachment 1 to the standard. The Attachment can be used directly or modified as necessary to reflect the dozens of actual installation configurations. The Attachment sets the basic structure and data needed. The visual diagram provides for easier entry by the Generator Owner and application of information for Transmission Planner simulation models.

The following questions will assist the SDT in finalizing the development of MOD-024-2 Verification and Data Reporting of Generator Real Power. For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. To improve this first draft of MOD-024-2 Verification and Data Reporting of Generator Real Power, the SDT would appreciate responses to as many of these questions as you can answer.

1. MOD-024-1, Verification of Generator Gross and Net Real Power Capability, was approved by the NERC Board 2/7/2006. It has not been approved for enforcement under Section 215 by FERC because it contains "fill-in-the-blank" characteristics with responsibilities assigned to the Regional Reliability Organization. Megawatt data is currently collected and reported under several other standards as well as many market rules. Do you feel that there is a reliability need for this additional empirical data, or should this standard be retired? Please explain.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT believes that verification should be performed on units that are connected down to 100 kV. The SDT believes this is consistent with the current Compliance Registry. The SDT has also provided how verification should be handled in plants/facilities that are greater than 75 MVA in aggregate gross nameplate rating. The Standard requires a separate verification for every unit greater than 20 MVA gross nameplate rating and connected at the point of interconnection of 100 kV or above. The remaining units in a plant/facility can be verified separately or in aggregate as the Generator Owner chooses. Do you agree with the SDT's decision to have the Standard be applicable to facilities connected to 100 kV and above and verified as proposed? Please explain.

   ☐ Yes

   ☐ No

   Comments:

3. After much discussion the SDT decided to require the verification be performed over a period of at least "one continuous hour" regardless of the type of unit because most units have reached steady state operation within one hour. Do you agree with this approach? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

4. The SDT felt that units that cannot sustain continuous operation, oftentimes known as intermittent, variable or limited energy units, such as a Wind Generating Station or run-of-river hydro, etc., should be exempt from this standard because such units are typically represented in studies with "on average" or "discounted" values. Do you agree with this approach? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

5. The SDT has developed a separate periodicity approach for identical units at the same site in Number 4.4 of Attachment 1. The Generator Owner would only be required to verify 20% of these units per year. Do you agree with this approach? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

6. The SDT believes that every Resource Planner and Planning Coordinator does not necessarily perform studies involving generating unit verified capability at the same time each year nor do they necessarily need current verified information at the same time. The SDT has developed Requirement R2 that requires the Resource Planner and Planning Coordinator to provide a schedule for receiving verified information that best fits the schedule and needs for performing studies. Do you agree with this approach? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

7. Are you aware of any regional variances that would be required for this standard?

   ☐ Yes

   ☐ No

   Comments:

8. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

   ☐ Yes

   ☐ No

   Comments:

9. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please provide a reference to the section, requirement or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal.

   ☐ Yes

   ☐ No

   Comments:

Resolution of Issues Associated with MOD-024-1

Source	Reference No.	Standard No.	Project No	Language	Resolution
Fill in the Blank Team		MOD-024-1	2007-09	Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards.	The SDT has decided to issue both MOD-024 and MOD-025 concurrently for Balloting.
Fill in the Blank Team		MOD-024-1	2007-09	Remove the fill-in-the-blank aspects (correct reference to "…Regional Reliability Organization's procedures…").	The SDT is addressing the fill-in-the-blank issue through its drafting of proposed revisions to MOD-024; the proposed revisions include the verification requirements within the body of the standard.
Fill in the Blank Team		MOD-024-1	2007-09	Goal is uniform North American standards for real and reactive power verification. Look at regional requirements and identify the best practice, commonalities and differences, and whether differences are needed for reliability.	The SDT reviewed the results of field testing of these standards – the field tests were conducted over multiple regions without the need for any regional variances. The GV SDT does not make any distinction in its proposed revision of MOD-024 between regional location of generator. This will be a continent-wide Standard.
Phase III/IV Team		MOD-024-1	2007-09	No requirement for the RRO to demonstrate that its procedures result in accurate information of gross and net real power capability of generators for steady state models	The GV SDT does not make any distinction in proposed revision of MOD-024 between regions and has developed language to permit the use of ambient data collection method.
Phase III/IV Team		MOD-024-1	2007-09	It is not clear in R3 to whom the Generator Owner will report the information.	The proposed revision of MOD-024 clarifies this issue by specifying the recipients of the information.
Phase III/IV Team		MOD-024-1	2007-09	Non compliance levels are too strict. A small utility with 15-20 units will be L4 non-compliant if they miss one unit	Compliance elements not yet drafted. SDT considering several potential solutions. The SDT must propose Violation Severity Levels (VSLs) (which have replaced levels of noncompliance) that meet FERC guidelines for setting VSLs - and one of those guidelines stipulates that VSL assignments should be based on a single violation, not on a cumulative number of violations
Team Comments		MOD-024-1	2007-09	Provide clarity where the Planning Authority is mentioned	The SDT has assigned a requirement to the Planning Coordinator in MOD-024 revision and, in accordance with the Functional Model, this is an appropriate assignment. The requirement assigned to the Planning Coordinator assumes that the Planning Coordinator needs data from

Source	Reference No.	Standard No.	Project No	Language	Resolution
					the Generator Owner for planning models.
FERC Order 693		MOD-024-1	2007-09	Require users, owners, and operators of the system to provide this information.	The proposed revision of MOD-024 clarifies this issue by specifying the appropriate functional entities in the Applicability section and by updating the requirements so that there are no fill-in-the-blank elements.
FERC Order 693		MOD-024-1	2007-09	Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions can be determined.	This issue is addressed by having the Generator Owner provide the data corrected to the temperature value specified by the Resource Planner and Planning Coordinator.
FERC Order 693		MOD-024-1	2007-09	Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval. The confusion centers on “approval” and when the 30-day period starts.	The SDT is addressing the fill-in-the-blank issue through its drafting of proposed revisions to MOD-024. The proposed revision achieves the same reliability intent as the original MOD-024 without including any references to approvals or 30-day periods.
FERC Order 693		MOD-024-1	2007-09	Provide a work plan and compliance filing regarding the collection of information specified for standards that are deferred.	See 3 year Work Plan filed each year in the 4th Quarter. This item is for NERC, not the SDT.

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Standards Announcement

Comment Period Open
January 18-February 18, 2010

Now available at: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Project 2007-09: Generator Verification

The Generator Verification Standard Drafting Team is seeking comments on the following documents **until 8 p.m. EST on February 18, 2010**:

- MOD-024-2 — Verification and Data Reporting of Generator Real Power Capability
- Implementation Plan

The drafting team has also posted a table explaining how it is addressing issues identified for MOD-024-1.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Next Steps

The drafting team will draft and post responses to comments received during this period.

Project Background

This project includes six standards to address generator verification needed to support bulk power system reliability – four proposed standards and revisions to two existing standards. The purpose of the project is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

Applicability (MOD-024-2)

Generator Owner
Planning Coordinator
Resource Planner
Specific facilities (see standard)

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Individual or group. (47 Responses)
Name (28 Responses)
Organization (28 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
Question 1 (43 Responses)
Question 1 Comments (47 Responses)
Question 2 (41 Responses)
Question 2 Comments (47 Responses)
Question 3 (42 Responses)
Question 3 Comments (47 Responses)
Question 4 (42 Responses)
Question 4 Comments (47 Responses)
Question 5 (41 Responses)
Question 5 Comments (47 Responses)
Question 6 (42 Responses)
Question 6 Comments (47 Responses)
Question 7 (43 Responses)
Question 7 Comments (47 Responses)
Question 8 (40 Responses)
Question 8 Comments (47 Responses)
Question 9 (42 Responses)
Question 9 Comments (47 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
Yes
The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
Yes
The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
Yes
Yes
Yes
No
No

The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
No
Individual
Ray Phillips
AMEA
No
The two questions the SDT asked on question 1 could have two different answers. I answered no to the additional data and yes to retire this standard. The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
No
The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES. The many of the regions have identified generators connected below 100 kV that are material to the BES and likewise have identified generators connected at or above 100 kV that are not material to the BES.
No
The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
Yes
The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
No
The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
No
The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
Yes
The current MOD-024-1 allows the regions to determine which generators must provide the requied data. Regions like SERC have developed regional supplemental standards that identifies such generators. The draft MOD-024-2 contradicts SERC's regional supplemental standards and totally removes SERC and other regions from the decision making process.
Yes
Since SERC's supplemental standards have not yet been approved by FERC I consider them proposed standards. The current MOD-024-1 allows the regions to determine which generators must provide the requied data. Regions like SERC have developed regional supplemental standards that identifies such generators. The draft MOD-024-2 contradicts SERC's regional supplemental standards and totally removes SERC and other regions from the decision making process. The draft MOD-024-2 conflicts with the new CIP standards regarding the size of significant generators.
Yes
The draft MOD-024-2 removes the decision making ability of the only entities (PC, regions, etc.) that actually know which generators are material to the BES. Instead the draft uses a blanket approach to basically include all generators 20 MVA and above connected at 100 kV and above. This approach will reduce the reliability of the BES due to distraction caused by the deluge of data from a multitude of generators that are not material to the BES and will exempt material generators that are connected below 100 kV.
Individual
Scott McGough
Oglethorpe Power Corporation

Yes
Yes
Yes
Group
Generators Supporting Elimination of MOD-024
Thomas J Bradish
No
The generator owner/operator provides unit real power capability in six standards other than in MOD-024 plus the TOP/RC/BA/ISO see a unitâ€™s real time output via their EMS. MOD-024 is duplicative and, as such, unnecessary. Planners on the RFC MOD-024 draft standard drafting team argued that they needed to know what a unit could consistently produce over a 7-24 hour period when running their reliability models. They were not interested in knowing short-term unit capability. Another reason for not using the unitâ€™s output under a stressed condition is that it is not at a level of reliable output. A unit can generate the real power during a test but many times not under actual system conditions. These tests are conducted at the most favorable time for unit performance and are only indicative of unit performance at that point in time. They are no guarantee of future performance. This results in system operators not getting the real power output that they thought was available to them. This shortage of real power occurs during system emergencies when system operators need the mega-watts the most. Because of this, these mega-watts have been called paper mega-watts. Requiring a test actually fosters a situation counter to ALR. Every unitâ€™s output must be metered and its output is monitored in real time in the TOP, RC and/or ISO Energy Management System (EMS). The EMS would have a history of a units output. This data is the most accurate representation of a unitâ€™s capability under actual system conditions and is a true representation of actual unit capability. This actual unit production data can be made available to the transmission planners. The transmission planners can analyze EMS data and use that period of unit performance that meets their requirements. If they are interested in a unitâ€™s performance during the period of highest demand, they can analyze unit output during the most recent or previous peak demand period. By using actual data, the paper mega-wattâ€™s issue goes away. If the planner has any issues, they can discuss these directly with the generator operator/owner. Requiring the planner to analyze EMS data may have another benefit. It will force the planner to become more engaged and communicate more strongly with the real-time system operators. The planner will become more aware of real-time issues that will enable them to incorporate these anomalies into their system models. Another benefit to using actual unit data is that it will eliminate running the unit to perform the MOD-024 verification. Not having to run a unit that is not needed to meet system demand will result in fewer emissions and fuel consumption yielding a higher level of environmental stewardship. As a nation, we are supposed to be concerned about greenhouse gases and efficient use of carbon-based fuels. Forcing units to run is contrary to these national goals. Unit real power capability is specified in the units interconnection agreement with the TO. The GOP is required to report unit de-rates to the TOP, RC, BA or ISO immediately after they occur. Real power reporting requirements currently appear in six (6) standards as follows: FAC-002-0: R1. The GO, TO, Distribution Provider (DP), and Load-Serving Entity (LSE) seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include: R1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems. R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0. MOD-010-0 Applicability 4.3. GO specified in the data requirements and reporting procedures of MOD-011-0 R1. MOD-011-0 R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status. TOP-002-2a R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested. R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007) R14.1. Changes in real

output capabilities. (Effective August 1, 2007) R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output). TOP-003-1 R1. Generator Operators and Transmission Operators shall provide planned outage information. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection. R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required. R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas. TOP-006-2 R1` Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. R1.1 Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. Because the generator owner/operator provides unit real power capability in six standards plus the TOP/RC/BA/ISO see a unitâ€™s real time output via their EMS reporting the generator testing and reporting contemplated under MOD-024 is unnecessary. In addition, MOD-026 and 027 have not been considered in this discussion but are anticipated to be approved over the course of the next two years would cause further duplication. Thus, MOD-024 is clearly unnecessary.
NA. This standard is not needed for reliability.
NA. This standard is not needed for reliability.
NA. This standard is not needed for reliability.
NA. This standard is not needed for reliability.
NA. This standard is not needed for reliability.
No
NA. This standard is not needed for reliability.
NA. This standard is not needed for reliability.
Individual
Martin
Bauer
No
The changes in this standard duplicate and conflict the requirement specific under TOP002. Originally this standard was for verification procedures which were used to meet TOP-002. The verification procedures defined in this standard should be incorporated into TOP-002 if this standard is retired.
Yes
No
The intent of the requirement of the previous version was to provide realistic summer and winter generator capability. For hydro units, the process detailed in this version only provides a vague assessment of normal and most likely not be the realistic capability of the generator. The process requires the units to be operated â€œnormallyâ€ which is undefined and to adjust the MW to reflect forecasted (summer or winter) reservoir conditions. Hydro units may be â€œnormallyâ€ operated throughout their operating range. Without specific guidance that the operation should utilize a normal â€œfull loadâ€ condition, the true summer capability may not be known. Specifically, if a generator , at some time other than summer is, operated at 50% gate during the operational snap shot produces xx MW, then the xx MW at 50% gate will be indexed for the summer reservoir level. The true capability of the generator at 100% gate (normal full load) during summer would actually be much higher. The language would need to ensure that the full load would reflect limitations other than those introduced by head.
No
It is not appropriate to consider the variability of wind generating stations comparable to the operation of a run of the river hydro. Run of the river hydro tends to be less variable and pose a lower regulation burden on the BES than wind generation. We justify this position in that the operator can estimate the energy produced during a month and even schedule the capacity at which the generator is operated, whereas wind cannot. As such an operator is able to provide a verification of the capability of our run of the river plants.
Yes

No
This standard is not consistent with the NERC functional model in that it requires the submission of information is not consistent with the role of the Resources Planner. The Resource Plannerâ€™s role is to develop a long term plan for resource adequacy of specific loads within a Resource Planners area. The information furnished under this requirement would be valid for less than one year. Forecast reservoir operations are notoriously inaccurate at more than 9 months. The forecast seasonal variation is relevant for TOP and BA functions. Resource Planners would interested in average seasonal variations and any physical changes to generator capability (e.g. de-rating, up-rating, etc).
Yes
This standard conflicts with TOP-002
Yes
The requirement will result in continuous reporting by the Generator Owner for its hydro units. The capability of hydro units can vary seasonally by more than 50 MW in less than 6 months. It is unclear what reliability purpose is served by this requirement. As stated in the general comment section, Generation capability is forecast, adjusted, and provided to TOPâ€™s and BAâ€™s under TOP-002-2.
Individual
Jonathan Appelbaum
Long island power Authority
Yes
No
Units below 100 kV may in the future be registered with NERC under the materiality clause. LIPA suggests relying on the MVA rating only. Additionally, LIPA requests that in the Applicability section a statement clarifying that the point of interconnection may not be a BES element.
Yes
Yes
Yes
Yes
No
No
No
Individual
Russell A. Noble
Cowlitz County PUD
Yes
Yes the Standard should be retired. This standard appears to duplicate and complicate FAC-008 and FAC-009. If this standard remains, then should generator rating be removed from FAC-008 and FAC-009?
Yes
This approach makes it easy for the owner to know when compliance is necessary. However, 20 MVA redline across the board for any single unit seems too low. Any significant generation will be connected at 100 kV or greater, but not all generation is significant just because it is connected at a certain voltage. A simple redline is easy to manage, but is new small generation development being discouraged with this low bar? I am not dead set against this applicable level, but I think some research into discovering the unintended consequences should be made.
Yes
Yes
Wind generation canâ€™t buttress reliability in a pinch, therefore should not be included. Agree with the run-of-river argument. However, there are other generation plants that are limited by

FERC license to the maximum cubic feet per minute of water permitted to flow through the tail race. Such generation will have name plate ratings well above the allowed possible power generation considering the available prime mover. Therefore the limiting factor is not the ambient temperature, or the thermal aspects of the generation units, but the efficiency of the generation plant to convert the maximum allowed prime mover into electrical power. This efficiency will not change much, if at all, over time. Such units should also be exempt except for a single test at maximum allowed flow.
Yes
Yes
As long as it does not conflict with operational constraints of the generation plant.
No
Yes
Maximum hydraulic flow constraints by operation license can legally prevent maximum name plate capacity verification tests.
Yes
Ambient temperature correction calculation requirements may incur significant compliance costs with little return for the effort. Will the Planner be asking for operation output vs. ambient temperatures way beyond normal levels? If the required ambient temperature is beyond the operational testing ability (i.e. 500 year high), how will the engineering analysis be established and verified?
Individual
Edwin Thompson
Consolidated Edison Co. of New York
Yes
There is a need to test the gross and net real power capability because it is a key operating and planning horizon requirement to maintain system reliability. Unit testing is critical to System Operations and their ability to respond to contingencies. Even now, there are concerns with interconnection frequency responses and units not responding to AGC signals as noted in the 2-11-2010 NERC Industry Advisory on interconnection frequency response. In addition, as more and more wind generation is installed, generation capability issues will become more important to System Operators. The standard should not be retired, but the requirements should be incorporated into a new FAC standard or included in FAC-008.
No
SDT should not make reference to a specific voltage level. The SDT should indicate that verification should be performed on units that are connected to the Bulk Electric System as determined by the Region.
No
The SDT should change the verbiage to â€œa minimum of one continuous hour of normal operationâ€ to avoid confusion that the unit can be ramping up to full load during the test.
No
All units meeting the voltage level and output level as specified in Section 4.2 should be tested. From both an operating horizon and planning horizon, it is important to have an accurate model of the system.
No
Please see response to question 4. In addition, terms such as â€œidentical significant control systems settingsâ€ and â€œsimilar verified capabilitiesâ€ are ambiguous. Section 4.4 of Attachment 1 should be removed.
Yes
In addition, different regions of the country may have summer or winter peaking periods and will schedule tests accordingly.
No
No
Yes
MOD-024-2 requires bi-annual testing, while at the same time exempted intermittent units (e.g. wind generators) and stations with multiple units (section 4.4). A reliability standard should support reliability; therefore, all units should be tested at the same frequency. The DT should consider a reliability standard that has an annual test requirement only that tests all generation units, regardless of type (including intermittent units or stations with multiple units). A region

can also develop bi-annual requirements for a summer and winter test if they see a reliability benefit and/or have a market requirement. Concerning R1: The requirement does not specifically state who should receive the generator unit capability data. The PC? The RP?
Individual
Baj Agrawal
Arizona Public Service Co.
No
There is no reliability need for this standard and it should be retired. It does not serve any purpose and no body uses this data.
No
There is no need to go down to registry level of 20 MVA. The variation in capacity of these small generators has no measurable impact on the grid planning study results. The studies have onsiderable more uncertainties due to other more significant variables. The minimum size should be 100 MVA for each unit or 250 MVA for a plant.
No
Our experience is that 30 minutes are adequate to reach steady state conditions. There are no benefits to be derived by going beyond 30 minutes.
Yes
Yes
Yes
The need for verification should also be left on the Planning Coordinator.
No
No
Yes
This standard is contradictory to new NERC policy of â€œresults-based reliability standards." NERC should not be developing a standard which it will have to withdrawa in a future review. If it is decided to go ahead with the standard, the reliabiltity benefits should be expalined.
Group
NERC Standards Review Subcommittee
Carol Gerou
Yes
Please review the possibility of redundancy within the following NERC standards: FAC-001-0; R1.1, Connection requirements for Generation facilities R2.1.3, Voltage level and MW and MVAR capacity or demand at point of connection. FAC-008-1; R1, GO shall each document its current methodology used for determining Facility Ratingsâ€¦ FAC-009-1; R1, GO shall each establish Facility ratingsâ€¦ MOD-010-0; R1, GOPs shall provide this steady-state modeling and simulation dataâ€¦ MOD-012-0; R1, GOPs shall provide appropriate equipment characteristics and system dataâ€¦ TOP-002-2a; R14, GOP shall notify the BA and TOP of changes in capabilities and characteristicsâ€¦ R14.1, Changes in real output capabilities
Yes
Yes
Yes
Yes
Please revise 4.4 of Attachment 1 4.4. Alternatively for multiple units installed at the same site where the units have identical designs, identical major components, identical significant control system settings and similar â€œtestedâ€ verified capabilities â€œper MOD-024â€: 4.4.1 Verify approximately 20 percent of all such units annually with all units being verified over a five year period. 4.4.2 Verify at least one unit each year if fewer than five units meet the criteria in 4.4.
Yes
R2 should be redacted to include variables and not be so constrained to temperature since there might be other variables besides temperature. These variables would be specified at the Planning Coordinator and Resource Planner discretion.
No
N/A

No
N/A
Yes
Requirement R1 â€“ The requirement should be clarified that in the case of Joint-owned-units, the Operator of the unit is responsible for verifying the capability of the unit. For R1, R2, & R3, we propose a Violation Risk Factor of â€œLowerâ€ and a Time Horizon of â€œOperations Planning, Long-Term Planningâ€. We propose â€œLowerâ€ for the VRF because more accurate real power capability values will be assured by this requirement, but reasonably accurate values are likely without this requirement. We propose â€œOperations Planning, Long-Term Planningâ€ for the TH because RCs and TOPs will use this data in their operations planning studies and PCs and TPs will use this data in their transmission planning studies. For R2, replace â€œdesired temperature to which the dataâ€ with â€œdesired ambient coolant temperature to which the summer and winter dataâ€ for added clarity. In Attachment 1, 3.2; replace â€œambient air temperatureâ€ with â€œambient coolant (air, water, etc.) temperatureâ€ because the capability of different types of generators is affected by the temperature of different cooling medium. In addition, consideration may need to be given to the average pressure level of generating units that use hydrogen for equipment cooling. Introduction, Section 4.2 - As written, small diesel generators at applicable Generating Facilities could be expected to be tested as part of this standard, even if these small generators are intended only for local site power, and are only capable of reaching a 100 KV interconnection by back-feeding through local site distribution circuits and auxiliary transformers. Based on the MVA metrics provided, it would appear their inclusion is not the intent, but the standard is ambiguous as written. On the Implementation Plan for MOD-024-2 for units that are to be verified every five years, they state the verification â €œwill begin five years after the compliance implementation date for annual units.â€ Wouldnâ €™t it make more sense to make them verify in the first year after the MOD-24-02 is adopted or approved and then do it every five years after that? On page 2 of 10, A.5. Effective Date, it seems unclear when they say verification â€œwill begin 30 calendar days following the first summer or winter peak periodâ€ . For example, if the summer peak occurs in June and you expect a higher peak in July or August and it doesnâ€™t occur, then you would be in violation. The same applies for the winter period. They donâ€™t define the summer and winter period. On page 5 of 10, MOD-024-2 Attachment 1. 2. Verify generating unit winter gross Real Power generating capability as follows: 2.1. They donâ€™t define the winter period and what the conditions should be for the verification test period. Please Clarify. On page 5 of 10, MOD-024-2 Attachment 1. 2. Verify generating unit winter gross Real Power generating capability as follows: 2.4. â€œby making a temperature correction to the most recent summer gross Real Power generating capability verification.â€ Under what conditions can temperature corrections be made?
Group
We Energies
Howard Rulf
No
We feel this requirement could be retired do to the fact that the data is collected and reported under several other standards as well as many market rules. For example, the Midwest ISO has established testing requirements for generators under Module E of the Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff. We also feel that having multiple different testing and reporting requirements can potentially lead to confusion and errors in reporting. If it is determined to not retire this standard, a provision should be made that if generator testing information is provided to a RTO following prescribed testing standards of the RTO, the submittal of the information to the RTO would meet the requirements of MOD-024-2. There is also a concern regarding the different applicability requirements between MOD-024-2 (Generator Owner, Planning Coordinator, and Resource Planner) and the recently passed MOD-024-RFC-01 (Generator Operator and Planning Coordinator) which further illustrates the problem of consistency of requirements.
Yes
No
To the extent there are multiple reporting requirements for generator capacity data, a standard timeframe for reporting the information should be developed in order to minimize the potential for conflicting data on the same generator from being used for similar modeling purposes. In addition, to the extent that generator capability data will be adjusted based upon ambient conditions, the requirement to verify the summer gross Real Power generating capability only during the summer period is overly restrictive. Current standards for generator testing allows the results from any period of time to be used as long as the results are adjusted based upon

ambient conditions at the time of the test to the ambient conditions that would exist during the summer.
Yes
Under requirement R3, we question the necessity of reporting a 50 MW reduction in a unit within 15 calendar days of the determination that the reduction is expected to last more than 6 months. Given the current wording, this requirement would need to be understood by a very broad base of individuals who may not typically be aware of this reporting requirement (e.g. a maintenance supervisor evaluating the impact of damage to a mill) and the current wording is unclear as to when the 15 day clock would begin. Prior to making this a requirement, an evaluation should be done to determine how big of a problem this is currently causing to any system modeling, what the risks are of waiting until the next test date to report the issue, and whether or not the concerns change if a RTO has an annual testing requirement.
Group
GO/GOP
Silvia Parada Mitchell
No
No, we do not feel additional empirical data is necessary as we believe this version should include data required in Version 1 as this version gave a better description of what is happening with a generating unit during a test. Yes, we do feel this standard should be retired. We believe this standard is unnecessary since real power verification can and should be handled by generation and transmission agreements. The Generator Owner (GO) & Generator Operator (GOP) provide generation unit real power capability in seven standards other than in MOD-024 plus the Transmission Operator (TOP), Reliability Coordinator (RC), Balancing Authority (BA) and Regional Transmission Organization (RTO) / Independent System Operator (ISO) see a unitâ€™s real time output via their Energy Management System (EMS). Therefore, the generator testing and reporting contemplated under MOD-024 is unnecessary. In addition, MOD-026 and 027 have not been considered in this discussion but are anticipated to be approved over the course of the next two years would cause further duplication. Thus, MOD-024 is clearly unnecessary.
Yes
No
We feel that one hour is too short. We recommend verfication be performed one hour after the unit has reached steady state operation since some units may take different lengths of time to reach steady state.
Yes
Yes
No
We do not agree with this approach. Validation should be performed during a period which is mutually agreed upon by both the GO and TOP to take into account seasonality. For the other periods, validations should not be required.
Yes
Different regions have different peak seasons depending on the climate.
No
Yes
We believe this standard should be retired in its entirety.
Group
Exelon Generation Co LLC
David P Belanger
No
The standard should be retired there is presently an number of different standards the require Generators to provide the same information.
No
Short duration testing conducted when conditions are the most favorable do not provide an accurate indication of unit preformance under all conditions.
Yes

No
By using information already gathered through the EMS during unit operations for market reasons would elimiate the need for "testing only" runs redusing unnecessary fuel, emmissions and start up stresses on units.
No
Using real time data from EMS would allow planners to have access to dat for anytime of year and system conditions elimiating the need to schedule testing.
No
No
No
Individual
Greg Mason
Dynegy Inc
Yes
Planning related entities (i.e. Planning Coordinator, Resource Planner and Transmission Planner) need the maximum (normalized)demonstrated capability of generating units for inclusion in their planning models. No other Standard requires this data to be accumulated and reported to these entities. Also, historical EMS data that reflects economic dispatch and regulating requirements is not an alternative source for this data.
Yes
Yes
Yes
Yes
No
The Transmission Planner also needs this generator data. These planning entities should not be required to provide the desired temperature to which the data needs to be adjusted. Generator Owners should simply adjust the actual test data using average temperature data from a location near the plant. This provision has been incorporated in the related RFC Regional Standard MOD-024-RFC-01.
No
No
Yes
1. Applicability 4.1- Transmission Planner needs to be added as a Functional Entity. All Planning related entities (i.e. Planning Coordinator, Resource Planner and Transmission Planner) need the maximum demonstrated capability of generating units for inclusion in their planning models. 2. Requirement R2- Adjustment of generating verification data should not be dependent on a request from a planning entity. This data should be adjusted to an average temperature in all cases and recorded on Attachment 2. 3. Attachment 1, Item 3.4.5- Modify this item to correspond to recommended changes in Requirement R2 (see above comment #2). 4. Attachment 1, Item 4.5- The phrase â€œdoes not run with the periodicity described in 4.1 through 4.4â€ â€ is ambiguous. No â€œperiodsâ€ are included in Items 4.1 through 4.4 in Attachment 1. The intent of this provision needs to be clarified.
Group
Electric Market Policy
Mike Garton
No
We agree that a standard for Verification of Generator Gross and Net Real Power Capability is needed. We support the data being requested in standard MOD-024-2, Attachment 1 and 2.
Yes
Yes

Yes
Yes
Yes
No
We are not aware of any regional variances, but are aware that regional standards are under development.
No
Yes
1. Requirement R1 states to â€œsubmitâ€ the Real Power generating capability: however Requirement R2 appears to suggest that the data be submitted only when requested by the Resource Planner and/or Planning Coordinator. Therefore, we suggest you remove the words â€œand submitâ€ from R1. Requirement R2 â€“ the first bullet should be revised to indicate â€œdesired conditionâ€ to which the data is to be adjusted. 2. â€œSummer periodâ€ and â€œsummer seasonâ€ appear to be used interchangeably in Attachment 1. The same comment applies for winter.
Individual
Jon Kapitz
Xcel Energy
Yes
We believe there is a reliability need for the Megawatt data collected per this standard and consequently this standard should not be retired.
Yes
Yes
While we agree that one hour of data is adequate to verify the capability, in our experience it takes at least 30 minutes for a steam turbine unit to stabilize if it has been operating at a lower load. We believe the criteria should take into consideration of an applicable "stabilization period" prior to data collection.
Yes
No
We are in agreement with the concept as long as the caveats that the major components and control systems are identical and that the verified capabilities are similar remain in the wording.
Yes
Yes
Some Regional Entities have developed their own requirements as directed under MOD-024-1. These would presumably take precedence over MOD-024-2. Some RTOâ€™s (e.g. MISO) have their own requirements for capability verification.
No
Yes
With regard to Attachment 2, the only ambient condition that is required to be reported is ambient air temperature. This has a significant impact on combustion turbines, but little effect on steam turbines. Condenser cooling water temperature has much more impact on steam turbine capability and we feel this should be recorded for that type of prime mover. Also, we would like to request that a description of the process for performing ambient compensation be included either in Attachment 1 or in a separate Technical Guideline to improve the quality and consistency of the information that is reported.
Individual
Kenneth D. Brown
Public Service Electric and Gas Company
No
The standard should be retired. There are several other standards pursuant to which the GO and/or GOP provides real power capability to those parties needing that data. Also, the RTOs, ISOs, in their role as TOP, RC and BA receive actual data continuously via the EMS. Likewise,

those entities performing the same functions in non-ISO areas also receive the data. The actual operating data collected through EMS systems is far superior in quality to that resultant from compliance with MOD-024, both presently and as proposed. Imposing duplicate burdens on generators with no commensurate benefit to reliability should be avoided. Hence, MOD-024 is not necessary.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
No
N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
Individual
James H. Sorrels, Jr.
American Electric Power
No
Yes
Yes
No
AEP believes that it is important to have intermittent, variable, and limited energy units to be in compliance with this standard. Technical assumptions made for studies are important, but it is important to ensure that the stated capabilities for such units are verified.
Yes
Yes
No
There are no additional variations known beyond those variations already accommodated in the draft standard.
No
No known conflicts.
No
Individual
Marty Berland
Progress Energy
Yes
Yes - there is a reliability need. No, the standard should not be retired.
Yes
No
We agree with the approach as stated in Question 3 but have selected NO here because the proposed standard itself does not reflect the approach stated. For Attachment 1, Sections 1.1, 1.2, 2.1, and 2.2, these should be changed to say â€œfor at least one continuous hourâ€¦â€
No
While we have indicated that we disagree with the exemption, it may be more appropriate to address testing of â€œintermittentâ€ resources separately due to their different use in planning

and operational studies. However, we think the basis for exemption by the SDT is incorrect. The SDT has confused the issue of rating with how that rating is used in planning studies. There are two fundamental questions that must be answered for each resource in any planning study: (1) what is the resource capable of producing under some standard set of conditions, and (2) how much will it produce under the conditions assumed in a planning study. Historically, these two questions are merged for resources which are dispatchable and controllable to a sustained output level. In other words, if we test a conventional fossil or nuclear generator and determine it can produce X MW under the test conditions, we assume it can produce X MW under study conditions like peak demand, off-peak or shoulder load conditions. However, we might model the unit as producing zero or something less than its capability due to economic or some other dispatch consideration. We do not try and represent some average value of its production over time. When intermittent resources are considered, we still need to know how much a unit is capable of producing at its maximum output. We would not size the interconnection for â€œaverageâ€ output. We need to know what it might produce under ideal conditions. Taken further, we know that at some point in its operation, the intermittent resource will produce at its tested value, and it will be up to the planner to determine if that condition needs to be studied. For example, 100 MW of nameplate generation may produce 30 MW on the average over a yearâ€™s time, but it might produce the full 100 MW at an off-peak hour, and that may need to be studied. How do we assure ourselves that the 100 MW of nameplate is actually capable of 100 MW? While intermittent resources may not make up a significant portion of supply in most regions at this time, future development may result in significant portions of supply being made up of these resources, and relying on design or nameplate values will be as inappropriate for these units as it is for existing generation. The standard should focus on determining the appropriate generator ratings to be supplied to the planning processes, not how they are ultimately used. As the standard itself states: 3. Purpose: To ensure that planning entities have accurate generator Real Power capability modeling data used in system planning studies
Yes
Yes
No
No
Yes
COMMENT 1-The first bullet item under R2 should be revised as follows: â€¢ the desired temperature to which the data is to be adjusted for conditions normally experienced for summer and winter periods. COMMENT 2- R3 should be revised as follows: "Each Generator Owner shall report to its Resource Planner and Planning Coordinator any change that is greater than 50 MW in the gross Real Power generating capability of any unit compared with the last verification submittal that is expected to last more than six months. The Generator Owner shall make such report within 15 calendar days of the determination that the change in capability is expected to last more than 6 months." COMMENT 3- For Attachment 1, Section 4.3, in â€œFor each individual generating unitsâ€¦â€ change â€œunitsâ€ to â€œunitâ€. COMMENT 4- Attachment 2, Requirement 3 provides for the RP and PC to provide the GO â€œthe desired temperature to which the data is to be adjustedâ€. Attachment 2 provides a blank to record that value for adjustment in each of the Summer and Winter Verification Data sections stated as: â€œThe recorded MW values were adjusted for the following average temperature conditions:â€ We suggest removing the word "averageâ€ which is inconsistent with R3. COMMENT 5- In Footnote 1, revise as follows for clarification: 1- If the winter verification is based on Summer data, provide only the date of the â€œsummerâ€ verification â€œusedâ€ not the start and end times. COMMENT 6- The standard does not address validation of initial Real Power Capability for new units.
Individual
Scott Berry
Indiana Municipal Power Agency
No
IMPA is anwering no to the question "Do you feel that there is a relaiblity need for this additional empirical data", and answering yes to the question "should this standard be retired". The reporting of megawatt data in other reliability standards and in market testing requirements for units is enough.
Yes
IMPA agrees that the standard should be consistent with the current Compliance Registry and supports how units are verified in the standard.
Yes

IMPA agrees with the one hour testing and the reasoning that the SDT used to decide on this time period.
No
If these units cannot sustain continuous operation, then they can report/record the highest hour or an average output for the hour.
Yes
Yes
IMPA agrees with this approach as long as it is for only receiving the verified information and not allowing these entities to specify any type of testing period or requirements outside of this standard.
No
Yes
This standard conflicts with the RFC approved standard, MOD-024-RFC-01. The NERC draft version of MOD-024 has the Generator Owner submitting reports to the proper entities. This conflicts with the RFC standard which has the Generator Operator submitting the reports to the proper entities. IMPA believes that NERC should resolve this issue by having the RFC standard agree with the NERC MOD-024 standard and the Functional Model. The SDT may not be able to resolve this issue, but it needs to be resolved or two different entities could be in non-compliance in the RFC region if a report is not submitted.
Yes
A clarification under number five, the effective date is needed. Under effective date, both sentences need to be clarified. Is the effective date the first day of the first calendar quarter after or part of the six months after applicable regulatory approval. For example, if regulatory approved is received on June 28, 2011 and then six months after is December 28, 2011, is the standard effective on January 1, 2012 (first day of the first calendar quarter after six months) or a date in the six months (before December 28, 2011).
Individual
Armin Klusman
CenterPoint Energy
No
CenterPoint Energy disagrees with having this Standard be applicable to all units connected to facilities 100 kV and above. CenterPoint Energy recommends it should only be applicable to units interconnected to Bulk Electric System facilities - not all facilities 100 kV and above are considered to be part of a Bulk Electric System.
No
CenterPoint Energy disagrees with exempting certain types of generation resources from Requirement 1 and Requirement 3; therefore, CenterPoint Energy recommends deleting 4.2.3 â€œVariable energy units such as wind generators, solar, and run of river hydro are exempt from the requirements of this Standard.â€ CenterPoint Energy agrees that oftentimes such generation resources are represented with â€œon averageâ€ or â€œdiscountedâ€ values. However, all planning models do not use â€œon averageâ€ or â€œdiscountedâ€ values as there are needs to study expected generation patterns. For example, wind generation typically peaks in the early morning hours in west Texas and should be modeled at a lower output in planning models which represent the peak load hour which occurs in the summer, typically around 5 PM. Transmission planners would need to ensure that there is adequate transmission when west Texas wind is operating at its peak output in the early morning hours. For this purpose, there is a need for a planning model with all wind generation operating at peak output. In addition, wind generation typically reaches a peak coincident with the peak load hour in the Gulf Coast area. So, this generation would be modeled at peak output in a planning model representing the peak load hour. In both of these cases, planning models need the net real power capability of wind units verified by actual unit testing.
Group
E.ON U.S.
Brent Ingebrigtson

Yes
obtaining the additional empirical data is helpful. The data required in Version 1 as established by the Regions gives a better description of what is happening with a generating unit during a test; this version only requires capability, auxiliary power usage, and temperaturesâ€"which does not give one a picture of what is occurring during a test and why the capabilities might have been the way they were.
Yes
No
One hour is too short. This period could allow a company to provide more of an "optimum" or "maximum" capability, rather than an average capability (e.g., during one hour soot blowers might not have to be run, etc.). The current 4-hour average test is more reasonable/reliable. Attachment 1 should be revised to specify a verification period of "at least 1 hour." The use of the term "normal operation" in Attachment 1 is not specific enough and is open to interpretation. Since generating capacity has market value, Gen Owners may desire to maximize the verified/reported capability of their units - even if such performance can only be attained for a single hour. This would not be consistent with the notion of dependable or continuous capacity which should be the basis used for reliability planning purposes.
Yes
E.ON U.S. believes that this is reasonable at the present time but with the proposed massive build-out of wind generation this may need to be re-visited in the future.
Yes
The language of 4.4 isnâ€™t clear â€"E.ON U.S. suggests revising to â€œIf 5 or more units are at a single site, verifyâ€¦.â€. Does â€œapproximately 20 percentâ€ imply rounding to the closest whole number? If 2 identical units are at the same site â€" no annual test is required but both units need to be verified within a 5 year interval?
No
The fundamental concept is correct; but, rather than ambient temperature, seasonal back pressure is much more appropriate to use for corrective factors. (e.g. with temperatures â€" is it wet bulb/dry bulb; humidity or not; how clean are the condenser/cooling tower?) All of these factors are satisfied by correcting to back-pressure conditions).
No
Summer peaking regional requirements are different than winter peaking regional requirements
No
This information requires some duplicate reporting. For example, the Kentucky Public Service Commission requires resource adequacy planning and reporting of the same data.
Yes
The first bullet under R2 should be modified as follows: â€œthe desired temperature and/or backpressure to which the data is to be adjusted.â€ Other criteria may also be required during the test. (e.g. MVARs, etc.) Clarify R3 language that 50MW is the change in unit rating â€" not any unit greater than 50MW. E.ON U.S. questions whether a 50MW threshold for capability change is less meaningful than using a percent of unit capacity threshold. Is the need to report such changes to NERC consistent with any Regional requirement? On Attachment 2, are data measuring points A,B,C and D to be reported as peak or average (over the verification period) values? MOD-024 and MOD-025 are linked and the STD has decided to revise each standard independently. This makes compliance difficult to maintain and test while the two linked standards are undergoing revision.
Group
Luminant
Rick Terrill
Yes
Luminant believes the verification of capability is needed to ensure unit capabilities utilized for resource planning, operating reserves and real time operations are accurate. â€œPaper Megawattsâ€ can have a detrimental effect on grid reliability.
Yes
No
Luminant would prefer 30 minutes at full load, as this approach has been utilized effectively in ERCOT for several years.
Yes
Yes

No
Luminant believes the test results should be submitted within 30 days of completion of the annual verification. Luminant submits the following modification to Requirements R1 and R2 to address this issue. R1. Each Generator Owner shall verify the summer and winter Real Power generation capability for each of its units in accordance with MOD-024-02 Attachment 1, Verification of Sumer and Winter Generating Unit Capability,and record and submit the verification information via MOD-024-02 Attachment 2, One-line Diagram, Table and Summary for Verification Information Reporting (or similar diagram and form), to the Resoruce Planner and Planning Coordinator within 30 calendar days of the completion of the Real Power capability verification. R2. Each Resourc Planner and Planning Coordinator that seeks verified generating unit Real Power capability data shall provide each Generator Owner: - the desired temperature to which the data is to be adjusted - the calendar dates that encompass the summer period and winter period.
No
No
Yes
Upon approval of MOD-024, Verification of Real Power and the companion standard MOD-025, Verification of Reactive Power, the applicability to Generator Owners and/or Generator Operators needs to be removed from FAC-008 and FAC-009. With actual verification of Real and Reactive Power, the FAC-008 and FAC-009 requirements become redundant for generators. Attachment 1 verbage needs to be consistent between the words "period" and "season". They are currently used interchangeably. Attachment 1, section 4.5, needs to be expanded so that when a lessor utilized unit is started up, it does not necessarily have to immediately run a maximum capacity test. The unit could have been brought online for capacity and the BA may not allow it to run at maximum output. Emergency situations may preclude running the test. This type of unit should be tested based on a schedule coordinated with the BA. All references to Attachment 2 should also include the "or similar diagram and form" language.
Group
FirstEnergy
Sam Ciccone
Yes
We believe that there is a need for this standard. The argument that "megawatt data is currently collected and reported under several other standards as well as many market rules" is not well founded. All Standard Drafting Teams assigned to revise existing standards that include some form of generator verification are proposing to retire their respective requirements because they intended that MOD-024-2 include these requirements. A specific example is the RTO SDT (Project 2007-03) which has proposed to remove requirements dealing with Real Power generator verification in TOP-002 (R13, R14, and R15) because they believe these requirements should be addressed by this GV SDT. The second part of the argument that these verifications are required by "many market rules" is also problematic because not every entity across the continent participates in a market and market rules are not enforceable Reliability Standard requirements.
Yes
We agree with the proposed thresholds because they are consistent with the NERC compliance registry.
No
We do not agree that one hour is sufficient for Fossil and Nuclear units (per Attachment 1 Sec. 1.1 and 2.1). The SDT should consider at least 4 hours or, at a minimum, require that the unit demonstrates it has reached equilibrium.
No
We believe that capabilities of intermittent units such as wind and solar can be adequately verified by testing, tracking of operational data, or calculations if testing or operational data is not possible or incomplete. Furthermore, it has been forecasted that utilization of these types of units will expand and most states will have Renewable Energy requirements of 20-25% of generation in the future. This would represent a large percentage of generating unit Real Power Capability not being verified. Excluding these units from verifying their capability will not improve reliability but will reduce it. The goal of this standard is to determine the capabilities of all generating units. The Generator Owner of intermittent units should provide their maximum capability through verification, test or calculation along with capacity factor data. This information could then be used by the Transmission Planner to plan for a reliable system based on the Transmission Planner's engineering judgment and considering other factors as the units Interconnection Agreement contractual arrangements (i.e. energy only unity, participates in a capacity market, etc.) Therefore, we suggest that this SDT incorporate requirements to verify

intermittent, variable, and limited energy units. We also suggest the SDT should consider language similar to RFC standard MOD-024-RFC-01 Requirement R2.2.3 to accomplish verification of intermittent, variable, and limited energy unit capabilities.
No
Item 4.4 of Attachment 1 should begin with the statement "For units that require annual verification ..." This would better clarify that the identical unit exemption is aimed at units that qualify under item 4.1 and 4.2. We agree that not all identical units should be required to be verified annually . However, the proposal should include a statement by the Generator Owner annually confirming which units that are deemed identical when providing annual verification updates for one of the identical units. Also, the wording proposed in 4.4, "approximately 20%", is ambiguous and up for interpretation in an audit. We suggest 4.4.1 be removed. We suggest replacing items 4.4.1 and 4.4.2 with the following: "The Generator Owner of identical generator units shall verify unit capability of at least one unit annually, such that all units are verified over a five year period."
No
It is unclear if R2 is intended to be a one-time submission of temperature adjustment information and schedule by the RP and PC or if this is something that is required each and every time the RP and PC would "seek" the data. Requirement R2 brings into question if the GO is simply holding verification data until requested to provide by an entity who "seeks" the data. Also, as written the RP and PC could provide conflicting temperature data and schedule expectations that would needlessly overburden the GO. As described in our item 4 in our Q9 response, FE suggests that R1 is ambiguous in regards to who the GO is to provide data to on an annual or every 5 year basis. FE suggests the team modify requirement R1 or Attachment 2 to clarify the intended recipients for either annual or 5-year generation verification data. In our opinion the GO should automatically provide the data to the intended recipients. Additionally, we propose the team to set a firm expectation that summer and winter verifications would be provide to the appropriate entities within 90 days of the conclusion of the applicable summer or winter peak period. In regards to temperature adjustment, the GO should simply provide any applicable temperature adjustment data used for the data provided and respond to inquiries from data recipients as needed and upon request. If the team elects to accept FE's proposed changes it is our opinion that R2 can be removed from the standard.
Yes
Our preference is that RFC retire their regional standard for Real Power verification (MOD-024-RFC-01) upon completion of this continent-wide standard. However, if RFC believes their standard is still needed after this NERC standard is completed, then there may be potential regional variances required as follows: 1. The threshold for periodicity of verification for RFC is 85 MVA; NERC is proposing 75 MVA. The gap between 75 and 85 MVA would need to be addressed. 2. RFC explicitly allows for testing, including commissioning tests for new units, in lieu of operational tracking. 3. The applicability for RFC is the Generator Operator while NERC proposes applicability to the Generator Owner. 4. RFC explicitly allows for exemptions and delays in verifications when system conditions or generator issues prevent verification.
No
Yes
FirstEnergy offers the following additional suggestions and comments: 1. We question the applicability to the Generator Owner (GO) instead of the Generator Operator (GOP). We believe the standard should apply to the GOP because the operation of the unit (operational verification and testing) impacts reliability more directly than ownership. In addition multiple ownership confuses responsibility and compliance. Only one GOP will operate a unit and perform the required verification, testing and data reporting. 2. The proposed requirements in this standard do not specifically allow for testing in lieu of operational tracking. We suggest the team add testing as an explicit alternative. 3. Several terms used in this standard should be defined to alleviate any varying interpretations; we suggest the following definitions: a. Summer/Winter Peak Period â€“ For the summer season, the Peak Period extends from the first day of June to the last day of August. For the winter peak season, the Peak Period extends from the first day of December to the last day of February. b. Peak Period Hours â€“ The four summer hours ending at 3 PM, 4 PM, 5 PM and 6 PM. The four winter hours ending 8 AM, 9 AM, 7 PM and 8 PM. c. Capacity Factor (expressed as a percent) - Is the net actual energy generation (MW-hours) divided by the product of the period (hours) and the net max capacity rating (MW) 4. R1 - It is not clear to whom the GO must submit this information. We suggest that the SDT add language in R1 that states the GO be required to submit verification information "as requested, in accordance with a predetermined schedule and format specified by a requesting Resource Planner, Planning Coordinator, or Transmission Planner". 5. R2 - First Bullet â€“ The phrase "The desired temperature" is too broad; we suggest a change to "The desired ambient temperature". 6. R2 â€“ If R2 is retained (see proposal to remove in our response to Q6), FE suggests the phrase "that seeks" be replaced with "having a reliability need for" since as written could have the unintended meaning that any RP or PC could request information of a particular generator

unit owner. 7. R3 - Regarding the 50MW level, it should be clear that this would be for situations where the MW level decreased by more than 50 MW. Significant increases in MW levels could violate interconnection agreements and be used by an entity to sidestep the required studies for facility uprates 8. Att. 2 - Diagram - The transformer downstream from the GSU should be the Start-Up Transformer, not Aux Transformer as currently shown. 9. In the background information provided by the SDT on pg.2 it states "... the SDT has taken the approach that the Transmission Planner needs to communicate the conditions under which the Generator Owner is to provide verified values..". It is not clear how this standard requires the TP to communicate the conditions. Was it the SDTâ€™s intent to say the PC or RP needs to communicate the conditions as stated in R2?
Individual
Greg Rowland
Duke Energy
Yes
While data is reported under MOD-010, MOD-024 provides for validation of the data.
Yes
No
Need to reword Attachment 1, section 2.1 to add clarity. Suggested rewording: For nuclear and fossil units, record data for at least one continuous hour of normal operation during the winter period. More time may be required or used to achieve stable conditions.
Yes
Yes
Yes
No
No
Yes
Industry guidance is needed on how to adjust recorded test data in Requirement R2 and Section 3.4.5 on Attachment 1. Itâ€™s unclear what is being sought by â€œadjustingâ€ data to a desired temperature. Ambient air temperature may not impact output nearly as much as coolant temperature, when the machine is not air cooled. Also, Section 3.4.5 should be expanded to allow for adjusting of data for factors other than ambient air temperature (e.g. steam leaks, condenser cooling water temperature, out of service reheaters, condenser fouling, turbine blade wearâ€¦.). Planners need to model to the unitâ€™s expected sustained capability. If tests are conducted under degraded plant or equipment conditions the test results need to be adjusted. Otherwise planners could plan the system for less than the full capability of the unit, which would yield a non-conservative result. Guidance is needed on how to report (i.e. actual data, adjusted data and a prognosis for sustained capability that may be achieved). The test should represent the actual condition of the equipment. If it is degraded then the unit would have less capability. However capability could be restored during a repair or outage, and demonstrated with another test.
Group
Electric Power Supply Association (EPSA)
Jack Cashin
Yes
See answer to question 9.
Yes
EPSA agrees with many of the SDTâ€™s findings in its review of current verification and data reporting practices. Entities that use generator real power capability data already receive and depend on the necessary data. The SDTâ€™s review confirms that capability data is often

already being provided due to existing requirements that should reduce the frequency for real power capability testing set forth in MOD-024. While planners have asserted the need for the data to improve modeling accuracy â€“ the SDT review of different planning models finds that they have inconsistent needs and donâ€™t facilitate a standard that supports reliability. EPSA respectfully requests that the SDT recognize the following objectives in crafting a standard that is responsive to FERCâ€™s directives in Order No. 693 (see 1310): 1. MOD-24 should not preempt or duplicate the real power verification procedures that already exist in the organized markets. 2. the frequency of real power verification in the organized market regions is driven by the annual capacity markets. System planning is a longer-term endeavor and as such real power verification for system planning purposes does not require the same annual frequency or level of precision. Thus, annual verification should not be required for any units, but rather all units should verify their real power capability on a longer cycle â€“ i.e., the five (5) year cycle currently proposed for certain smaller and low capacity factor units. A longer verification cycle reduces the need for unnecessary fuel burn and the uniformity results in better clarity as well as ease of implementation for Generator Operators.(note below) The SDT in its review also found that enhanced communication between entities will best facilitate the exchange of generator capability data. Further, it is worth noting that the Transmission Operator (TOP), Reliability Coordinator (RC), Balancing Authority (BA) and Regional Transmission Organization (RTO) / Independent System Operator (ISO) have access to a unitâ€™s real time output through their Energy Management System (EMS). The EMS provides updated information on a real-time basis, making further testing and reporting under MOD-24 duplicative and unnecessary. In addition, the GOP is required by other reliability standards to report unit de-rates to the TOP, RC, BA or ISO immediately after they occur, again making more frequent testing and data reporting under MOD-24 unnecessary. In addition, several existing Standards require the GOP to provide data related to generating unit capability status. Note: The capacity factor limitation simply may not be implementable if a unit has a capacity factor that fluctuates from year (i.e., if a 25 MVA unit has a CF less than 5% in years 1&2, but then exceeds 5% in year 3, then it needed to be tested annually and is non-compliant).
Individual
Jason Shaver
American Transmission Company
Yes
The requirements of this standard will provide empirical data that will improve system reliability.
Yes
The generating unit qualifications are consistent with the presently Compliance Registry criteria.
Yes
Yes
Yes
Yes
No
No
Yes
For R1, R2, & R3, we propose a Violation Risk Factor of â€œLowerâ€ and a Time Horizon of â€œOperations Planning, Long-Term Planningâ€. We propose â€œLowerâ€ for the VRF because more accurate real power capability values will be assured by this requirement, but reasonably accurate values are likely without this requirement. We propose â€œOperations Planning, Long-Term Planningâ€ for the TH because RCs and TOPs will use this data in their operations planning studies and PCs and TPs will use this data in their transmission planning studies. For R2, replace â€œdesired temperature to which the dataâ€ with â€œdesired ambient coolant temperature to which the summer and winter dataâ€ for added clarity. In Attachment 1, 3.2; replace â€œambient air temperatureâ€ with â€œambient coolant (air, water, etc.) temperatureâ€ because the capability of different types of generators is affected by the temperature of different cooling medium. In addition, consideration may need to be given to the average pressure level of generating units that use hydrogen for equipment cooling. Requirement 1: ATC believes that some additional clarity is needed as to those entities that will receive the information. Suggestion: â€œâ€¦submit to the Resource Planner and/or Planning Coordinator the information view MOD-024-2 Attachment 2â€¦â€ General Comment: It should be made clear that a GO validating and reporting a change in a unitâ€™s gross Real Power capability, in particular an increase in output, to comply with this standard, does not enable or give a GO the right to inject

said incremental output onto the transmission system. Any MW increase (regardless of duration or ambient conditions) must be formally considered via separate mechanisms for study and verification of the BESâ€™s ability to reliably support any such increase beyond that previously approved and included in a generation-transmission interconnection agreement.

Group

SERC Generation Subcommittee (GS)

Joe Spencer (SERC staff) / Jose Medina (NextEra-GS Chair)

The SERC Generation Subcommittee (GS) could not answer this definitively yes or no. The GS believes that reporting on MOD-024 is duplicative with other standards and may be retired. While this data is important, it is covered under: FAC-008/009, TOP-002, MOD-010/011, etc.

Yes

Stated or assigned values should be sufficient for modeling purposes for units having nameplate ratings < 75 MVA. This should apply to many regions. If the BA or TOP needs validated data on a smaller unit or group of units then these requirements can be made known to the GOP per TOP-002-2 R13.

No

We agree with the approach as stated in the questions but have selected NO here because the standard does not reflect the approach stated. For Attachment 1, Sections 1.1, 1.2, 2.1, and 2.2, these should be changed to say â€œfor at least one continuous hourâ€¦â€ to assure stable conditions.

No

While intermittent resources may not make up a significant portion of supply in most regions at this time, future development may result in significant portions of supply being made up of these resources, and relying only on design or nameplate values, for the purposes of transmission planning, will be as inappropriate for these units as it is for existing generation. The standard should focus on determining the appropriate generator ratings to be supplied to the planning processes, not how they are ultimately used.

Yes

Yes

Yes

The SERC Region is a summer peaking load region. Since unit capability (excluding hydro) is either independent of seasonal differences or will exhibit increased capacity for non summer periods, winter validation is not necessary. This would apply to summer peaking entities or regions.

No

Yes

Assuming this standard is not retired, the first bullet item under R2 should be deleted. If it is not, it should be revised as follows: â€¢ The data is to be adjusted for conditions normally experienced for summer and winter peak periods, as applicable. Industry guidance is needed on how to adjust recorded test data in Requirement R2 and Section 3.4.5 on Attachment 1. Section 3.4.5 should be expanded to allow for adjusting of data for factors other than ambient air temperature. Itâ€™s unclear what is being sought by â€œadjustingâ€ data to a desired temperature. For steam turbines, ambient air temperature may not impact output nearly as much as coolant temperature, when the machine is not air cooled.

Individual

Kasia Mihalchuk

Manitoba Hydro

Yes

If FAC-008 and FAC-009 are based upon design data and Engineering Analysis, a standard is required to complete field verification of the unit real power capability. There should be clear distinctions between these standards.

Yes

Agree to include units connected to 100 KV and above.

Yes

One hour testing is sufficient, and does not expose the unit to unnecessary stress or take excessive time to complete.

Yes

Wind generation and run of the river hydro units should be exempted.

Yes

Can the verification frequency of units be lowered to less than 20% for indentical units. Can it be 10% of identical uinits, as deterioration of unit real capacity is a very slow process unless a failure occurs (and failures are picked up by other standards)
Yes
State clearly who provides a schedule to whom. Is it Planning coordinator will provide a schedule to Resource planner for verified capability information of units? We would prefer that the requirement be to complete the testing at the required frequency, and to delete the requirement for creation and submission of a plan.
Yes
Regions with considerable hydraulic generation require verification of unit output that will be modified by calculation for rated head output for comparison. Exempting run of river plants removes this need for exemption.
No
MAPP was requiring unit capability tests in MRO region prior to MOD-024 NERC standard. The overlap with FAC-008 and FAC-009 should be carefully examined to avoid confusion.
Yes
The requirement R1 should be rewritten to include derivation of Summer and Winter ratings for Thermal units, and measured capacity corrected to design net head for Hydraulic units. R3 should be clarified to ensure it is only changes greater than 50MW that must be reported, not "any change for units that are greater than 50MW".
Individual
James Sharpe
South Carolina Electric and Gas
No
This standard appears to be redundant with TOP-002 R13. Also, Generator ratings are established in FAC-008. If a verification run by MOD-024-2 contradicts a rating established in FAC-008, which rating should an entity use? If the rating established by verification were used, would this not alter an entity's facility rating methodology?
Yes
Yes
Yes
No
Even though units may be identical in nature, variables such as actual in service time could lead to deratings and make two identical units unique. If the intent of the standard is to ensure unit generating capabilities are correct for studies, then shouldn't verification be made for all units?
Yes
No
No
No
Individual
Richard Kafka
Pepco Holdings, Inc
Yes
Planning Coordinators and Planning Authorities need the data
No
There is no need to define what already exists in BES definitions and in the compliance registry rules.
No
A Planning Coordinator should be afforded the right to request periods other than one continuous hour as needed for ad hoc evaluations e.g. for Ancillary Service evaluations over a 15 minute period or for special case studies e.g. fuel disruption analysis. The default period may be agreed to as one continuous hour but that should not be the mandated period.
No

Providing the Planning Coordinator with the flexibility for designing tests â€œneededâ€ for verification provides the opportunity to handle all units the same way (i.e. how the PC asked).
No
Identically designed units will not necessarily perform the same.
Yes
No
Yes
As noted in Question 1, this data is already being collected under other standards and in various organized markets. Coordination will be required to avoid conflicts
No
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
No
The SDT is asking two question at the same time, with possible contradicting answer. There is reliability need to collect this data. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards. If it is, the Standard (MOD-024) should be retired. If it is not done in other Standards this project should be pursued. Even if the collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements, in what way would the compliance and sanction be addressed? If there is a Standard that make it obligatory to respect tariffs, Market Rules, and Interconnection Agreements, this project could be retired.
No
See answer to Q1. HQT believes that there are some plants/facilities that are not connected to 100 kV but are material to reliability. These facilities should be subject to data collection, be it in this project Standard or in other existing Standards. The importance of generation to reliability is more related to its power than to its connecting voltage.
Yes
See answer to Q1.
Yes
Yes
Yes
No
No
No
Individual
Michael Ayotte
ITC Holdings
No
Yes
Comments: The 100 kV reporting for this requirement is consistent with other NERC reporting requirements.
Yes
None
No
Comments: A one hour typical rating/capability should be provided by the generators for run of river hydros.
Yes
None

Yes
None
No
None
No
None
No
None
Individual
Joylyn Faust
Consumers Energy
Yes
No
The MVA ratings should be based on Net Demonstrated Capabilities (NDC) rather than nameplate. There is no correlation between reliability and nameplate ratings.
Yes
Yes
No
Testing is arranged around scheduled unit outages. Unit ratings can be normalized to specific temperatures/conditions so results can be sent at any time.
No
No
Individual
Michael R. Lombardi
Northeast Utilities
Yes
Standard should be retired. The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
No
Individual
Fred Meyer
The Empire District Electric Company
No
This standard should be retired
No
I believe it is redundant to require both summer and winter ratings. Your summer raitings will be your "worst case" for understanding the maximum equipment output. Requireing winter ratings will only waste money and equipment wear.
No
The nameplate reating should be sufficient for determining output. In this day of being environmentally friendly, why would we as a country want to subject each generator to these

types of tests using precious fuel and expelling pollutants when nameplate ratings have been sufficient for years?
Yes
No
Nameplate data should be sufficient and verification is an overburdon to industry.
Yes
No
Yes
I am aware the state of Kansas has a current law that forbids units that start on Diesel fuel. This could cause some issues with smaller generators in the state of Kansas.
No
Group
Southern Company Transmission/Generation
Stephen Mizelle
No
We feel this standard is unnecessary since real power verification can and should be handled by generation and transmission agreements. Most traditional utilities already have a process in place to validate and/or certify unit capabilities. In the case of an IPP, this requirement can be addressed in the Transmission Interface documents. If this standard moves forward, then TOP-002-2 R13 must be deleted or at a minimum, revised to indicate that it addresses short term equipment issues in the operations horizon.
No
We recommend limiting the unit size requiring real power capability validation in paragraph 4.2 to the following: â€œGenerating Facilities connected at the point of interconnection at 100kV or above, containing an individual generating unit greater than or equal to 75MVA (individual gross nameplate rating)â€, for the following reasons: â€¢ Including only units > 75MVA will represent the vast majority of the total (cumulative) connected MW sources in the country â€¢ This cumulative MW class represents the units that are capable of having the largest impact to the stability and reliability of the BES â€¢ Excluding the smaller units will avoid unnecessary waste in time and money on the smaller units which individually do not appreciably affect the stability and reliability of the BES. â€¢ Stated or assigned values should be sufficient for modeling purposes for units having nameplate ratings < 75 MVA. If the BA or TOP needs validated data on a smaller unit or group of units then these requirements can be made known to the GOP per TOP-002-2 R13.
Yes
No
We recommend all hydro units be excluded since capability is dependent on available water levels. GOP's with appreciable hydro capacity have established procedures or processes to predict the capability of these units.
Yes
Yes
We agree with this requirement.
Yes
The SERC Region is a summer peaking load region. Since unit capability (excluding hydro) is either independent of seasonal differences or will exhibit increased capacity for non summer periods, winter validation is not necessary.
No
Yes
1. The subject standard should not require annual staged full load capability demonstration for verifying MW capability. There are many factors such as system load, economic dispatch, etc that determine if a unit is expected to be called to full load. This is especially true for the smaller (<75 MVA) units. 2. The requirement for ambient temperature monitoring during the verification period is unreasonable. The ambient temperature is not needed for unit operation, and may not be tracked, and in some cases may not be reliable. In these cases, either inaccurate data would be collected or added investment would be required. (The official ratings mentioned above are

based on performance data taken at or adjusted to specified ambient conditions.) 3. Allowances for different reporting format from that in attachment 2 should be permitted. We prefer a tabular reporting method due to the number of units in our fleet. An allowance for tabular reporting of the same information as indicated in attachment 2 should be permitted. 4. In Paragraph 3 of Page 5, we recommend replacing â€œNumberâ€ with â€œParagraphâ€. 5. The following comments relate to Attachment 2: a. On Page 7 we recommend the following: â€¢ moving the â€œDate of Reportâ€ and the associated blank line to the same line as â€œUnit Noâ€. â€¢ changing â€œAuxiliary Transformer(s)â€ below point A to â€œUnit Auxiliary Transformer(s)â€ â€¢ changing â€œAuxiliary Transformer(s)â€ below point C to â€œStation Auxiliary Transformer(s)â€ â€¢ splitting the bus just below the â€œPoint of Interconnectionâ€ and eliminating the single line diagram associated with point D. â€¢ adjusting single line diagram to fit on the page (displayed on a PC monitor) â€¢ change â€œMW (tertiary load, if any)â€, to â€œMW (GSU tertiary load, if any)â€ at the bottom of the page b. On Page 8, we recommend the following: â€¢ delete the point D measurement line from page 8 c. On Page 9 (Summer Verification Data), we recommend the following: â€¢ Insert a blank line between the â€œDate of Verificationâ€¦â€ line and the â€œVerification End Timeâ€¦â€ line.- in other words, make the summer and winter verification forms identical with respect to the Date of Verification, Verification Start Time, Verification End Time d. On Page 9 & 10 (Summer and Winter Verification Data), we recommend the following: â€¢ specify if the Aux Power (MW*) column in the table is â€œthe sum of the auxiliary loads shown on page 7â€ 6. R2 is not a requirement as currently written. It is a choice that the RP or PC makes. If he seeks verfied data, then he must provide certain things to the GO. If he chooses to not seek verified data, then he is not required to do anything. This means that M2 is wrong. The RP and PC should not be required to have evidence if they chose not to seek the data. 7. R1 requires the GO to submit information but it does not indicate to whom the data should be submitted. 8. R3: The threshhold for reporting a change in MW output is too high. A change of 10 to 50 MW in a generator's output could have an impact to system stability. The threshhold should be 10 MW. 9. Paragraph 2.4 in Att 1: The first word grouping is not a sentence and reads awkwardly. It is suggested that the words "an acceptable value can be obtained" be place in front of the words "by making a temperature". 10. Paragraph 3.4.2 in Att 1: Replace the word "since" with "if" for better clarity. 11. Paragraph 3.4.4 in Att 1: Move the words "in Attachment 2" to the position just after the word "flows". This will make it clear that the sentence refers to flows in Attachments 2 rather than units in Attachment 2.
Individual
Laura Zotter
ERCOT ISO
Yes
ERCOT ISO believes there is a need for this data. The verification methodologies, including the scheduling and timing of verification testing, should be left to the discretion of the relevant NERC functional entities â€“ e.g. the Planning Coordinator / Transmission Planner.
No
ERCOT ISO disagrees with this aspect of the proposal. Although, as a general matter, the relevant set of supply resources for reliability will be interconnected at 100 kV or greater, that is not an absolute rule. In fact, in the ERCOT Region there is a good amount of generation connected at 69 kV. The SDT should not preclude application of the proposed Standard to supply resources connected to facilities below 100 kV. 100 kV can be the default, but the requirement should provide for adequate flexibility to encompass other supply resources the methodology established by the relevant NERC functional entity includes such resources. Furthermore, this is consistent with the NERC Registry methodology, which accommodates facilities below 100 kV where they are necessary for/affect reliability of the Bulk Electric System.
No
ERCOT ISO disagrees with this aspect of the proposal. The methodology for verification should be left to the relevant NERC functional entities. As noted by the SDT, the Transmission Planner needs to communicate the conditions under which the resource is required to verify its real-power capability. This discretion afforded the TP should apply to all aspects of the verification, including the time period the unit must run. At a minimum, the proposed one-hour time period should be a default and the requirement should provide for alternative time periods to accommodate regional differences and different testing purposes â€“ e.g. for ancillary services.
No
ERCOT ISO disagrees with this aspect of the proposal because the performance/capability of all resources, including variable output resources, effects system planning and operations. Accordingly, contrary to the position of the SDT, the data from variable energy resources (e.g. intermittent renewable) is also needed for reliability. Although these resources are subject to the variability in terms of their fuel source (e.g. wind), there are methods of estimating the capacity and energy from these resources. These estimates provide value for the purposes of this standard. Variable energy resources should not be exempt from this requirement. The Standard should include these resources, provided that they are subject to rules that reflect the variability of their production. The verification methodologies established by the respective NERC functional

entities can accommodate variable resources in a manner that is consistent with the practices within their respective regions.
No
ERCOT disagrees with this aspect of the proposal. The assumption that all units of similar type at a plant are going to perform identically is not valid in all situations. Accordingly, to ensure any potential variances between similar units at the same site are accurately captured all such units should be required to provide verification annually.
Yes
ERCOT ISO supports this aspect of the proposal. The verification methodology and timing should be left to the discretion of the relevant NERC functional entities. As noted by the SDT, the needs for different Resource Planners and Planning Coordinators may vary. The Standard should enable the relevant entities to respect those needs, including the timing of the verification tests. By simply stating these entities should provide a schedule, the proposal provides adequate flexibility to respect regional differences. To accommodate the potential need for ad hoc testing, the requirement should provide for testing pursuant to the contemplated schedules â€œor as requested by the RP or PCâ€.
No
As discussed above, ERCOT ISO believes that there may be regional differences in the planning and operational studies where this information provides value. However, if the Standard is drafted to prescribe the reliability â€œendâ€ result or obligation, and it provides for adequate flexibility with respect to how the means implemented by the relevant entities to comply with the obligation, there should not be a need for regional differences. Revising the Standard in accordance with this general principle and the specific comments provided herein should affect this result and obviate, or at least mitigate to a great extent, the need for regional variances.
See response to Question 7 â€“ if the Standard provides adequate flexibility with respect to the means for complying with the reliability end prescribed by the requirements, this should mitigate any potential conflict.
Yes
ERCOT ISO believes R1 should clearly state to whom the Generator Owner of the Attachment 1 and Attachment 2 data should be submitted.
Group
PacifiCorp
Sandra Shaffer
No
: Information required under the proposed standard is currently submitted with FERC Form 1 and for FAC-008 compliance. This standard is redundant and should be retired.
Yes
No
: Sufficient detail on the data requirements during the one hour sampling period required under the proposed standard has not been provided. Please provide some direction on the required sampling rate and acceptable methods for data collection. It is unreasonable to require that a maximum boiler capacity test be performed twice a year to validate the unit real power capability. Biannual capture of historical data would be the preferred method of unit capability validation. Water resource impacts on hydroelectric facility capability have not been addressed sufficiently by the proposed standard. Please provide clarification on expectations for data collection at hydro facilities when water resources do not support operation at unit capability.
Yes
No
Current policies within the WECC require a testing interval of five years. This interval has been sufficient for stability studies to date. We suggest incorporation of a five year interval for generator real power capability validation in the proposed standard.
No
: Scheduling of generator capability verification should be set by the generator owner and generator operator within the five year cycle suggested in the Item 5 comments.
No
Yes
: Again, water resource impacts on hydroelectric facility capability have not been addressed sufficiently by the proposed standard and may result in conflict with other regulatory standards. Please provide clarification on expectations for data collection at hydro facilities when water resources do not support operation at unit capability.

Yes
: Suggest language in Section 2.2 to read â€œthe resource planner will assess the stated winter generating capability based on a test hour of generation corrected for actual vs forecasted water elevations and flows.â€
Group
Florida Municipal Power Agency and Some Members
Frank Gaffney
Yes
There are two potential reasons for the need to test generator capability related to the standards: 1) MOD-010-0 for accuracy of modeling purposes; and 2) for a potential standard on resource adequacy in the planning horizon (Project 2009-05?).
Yes
There is no need to expand the scope of the standard beyond the registration criteria. As the SDT has pointed out, only about 4% of the power system capacity is connected below 100 kV. Most of these generators are modeled, and many are already tested beyond the scope of the standard. So, causing regulation of generator verification to these generators may only improve accuracy for a small portion of the 4%. Such gain in accuracy at < 100 kV is easily overwhelmed by the inaccuracy of load forecasts, and by the variation of generator output with ambient conditions (e.g., temperature, humidity, barometric pressure, etc.) outside of forecasted ambient conditions. So, such effort is wasted because any supposed gain in accuracy by going below 100 kV is illusory and lost as compared to other forecast inaccuracies outside the control of anyone (e.g., the weather). If anything, the level of verification required in the standards could be reduced for smaller units (e.g., less frequent), even more so than as described in the standard. However, this would create a complex â€œtieredâ€ standard difficult to understand and monitor. Hence, we congratulate the SDT on developing a balanced perspective that truly focuses on what is important to maintain the reliability of the BES.
Yes
Yes
No
Degradation of capacity depends on more factors than design parameters, such as hours of run-time, time from last major maintenance, etc.
Yes
No
No
Group
SERC Planning Standards Subcommittee
Philip R. Kleckley
Yes
There is a reliability need to verify real power capability for larger units on the system as discussed in our response to Question 2 below.
No
In general there is no reliability need to verify MW values for small units because they don't significantly affect the reliability of the system. The criteria should be to verify individual units which are 75 MVA or larger or aggregates of units which are 75 MVA or larger. Also provision could be made for the TP or PC to request verification of units which are smaller than 75 MVA for the rare case in which they do impact the reliability of the system.
Yes
Yes
Yes
Yes
No

No
Yes
R2 is not a requirement as currently written. It is a choice that the RP or PC makes. If he seeks verfied data, then he must provide certain things to the GO. If he chooses to not seek verified data, then he is not required to do anything. This means that M2 is wrong. The RP and PC should not be required to have evidence if they chose not to seek the data. This situation can be fixed by revising R2 to read: "Each Resource Planner and Planning Coordinator shall request verified generating unit Real Power capability data and shall provide each Generator Ownerâ€¦" R1 requires the GO to submit information but it does not indicate to whom the data should be submitted. We recommend that R1 be changed to read: "Each Generator Owner shall verify the summer and winter Real Power generating capability for each of its units in accordance with MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability and record and submit the information to its Resource Planner and Planning Coordinator via MOD-024-2 Attachment 2 - One-line Diagram, Table and Summary for Verification Information Reporting." R3: The threshhold for reporting a change in MW output is too high. A change of 10 to 50 MW in a generator's output could have an impact to system stability. The threshhold should be a 10 MW change or greater. Paragraph 2.4 in Att 1: The first word grouping is not a sentence and reads awkwardly. It is suggested that the words "an acceptable value can be obtained" be place in front of the words "by making a temperature". Paragraph 3.4.2 in Att 1: Replace the word "since" with "if" for better clarity. Paragraph 3.4.4 in Att 1: Move the words "in Attachment 2" to the position just after the word "flows". This will make it clear that the sentence refers to flows in Attachments 2 rather than units in Attachment 2. The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Individual
Catherine Koch
Puget Sound Energy
Yes
Note: The way the question is worded with two opposite ideas makes it difficult to determine which box to check. Puget Sound Energy feels that this standard should be retired. This standard duplicates information required by other standards, including MOD-010, MOD-012, TOP-002 (R13), as well as FAC-009. Our Transmission Planners already request temperature related Real Power information for generating units through these other standards. Unit derates (proposed R3) are covered under TOP-002 R14, TOP-003, and TOP-006 R1.1. These other standards allow the Transmission Planners to customize their verification needs from the GO/GOP and not have a one-size fits all solution imposed on them as prescribed in this proposed standard.
Yes
Puget Sound Energy agrees with being consistent with the Compliance Registry. It seems that the compliance registry criteria would determine whether an entity has to comply with any of the NERC standards including this one and then the current BES definition would establish what facilities are applicable. The need to describe the Faclities under section 4.2 is not clear. We assume that any approved regional definition of the BES would dictate applicability ultimately. Regarding the verification requiremetns as proposed, it is unclear why annual verification (for most units) is necessary as much of the data will not change over an annual timeframe and most change that may occur would likely not cause a reliablity impact as it relates to the study work the Planning Coordinator or Resource Planner uses this information for. We would request that the testing be done on a 5 year cycle which follows other practices for providing data (i.e., WECC has been using a 5 year cycle for testing since 1997, and the results have proven to be entirely adequate).
Yes
Yes
Yes
However, we encourage this approach to test over a 5 year period for more that just identical units as discussed in our response to question 1. A 5 year cycle for testing is adequate.
No
While R2 allows flexibility in determining when the data is submitted, the Resource Planner/Planning Coordinator may not need this information each year. If that is the case, this annual requirement imposes an unnecessary burden on Planners and Generators to provide this information more frequently than necessary.
Yes

The WECC may want to continue using a 5 year cycle for testing. From the WECC experience testing annually for most units would be unnecessarily frequent.
No
No
Individual
James Manning, Bob Beadle, Dave Sofra
North Carolina Electric Membership Corporation
Yes
While we agree that there is a reliability need to verify real power capability for larger units on the system, we are of the opinion that the SDT should direct the verification at units that significantly affect the reliability of the BES.
No
In general there is no reliability need to verify MW values for small units because they don't significantly affect the reliability of the system. The criteria should be to verify individual units which are at least 100 MVA or larger or aggregates of units which are 100 MVA or larger and units that are connected to the transmission at 200 kV and above unless the generating units have been deemed by the Planning Coordinator as critical to the reliability of the BES. This is similar to what has been proposed in the PRC-023 standard under development. All other generators that do not meet this critieria should be exempt.
Yes
No
Peaking units that have a limited cumulative energy per year (i.e. low capacity factor below 5%) should be provided the same treatment. The SDT should consider providing the PC with the flexibility for designing tests â€œneededâ€ for verification such that all units are either handled in the same way.
No
The SDT should not be concerned with administrative details.
No
The concept that regular period-specific verification is not necessary. If the SDT is insistent on such a schedule established by the RP/PC, we would ask the SDT to consider circumstances where the same GO owns generators in multiple operating areas thus having to comply with varying requirements by multiple PCs. This would potentially result in the GO having to comply with different schedules of these multiple PCs which could be very difficult for the GO to comply with.
No
No
Yes
R2 is not a requirement as currently written. It is a choice that the RP or PC makes. If he seeks verfied data, then he must provide certain things to the GO. If he chooses to not seek verified data, then he is not required to do anything. This means that M2 is wrong. The RP and PC should not be required to have evidence if they chose not to seek the data. This situation can be fixed by revising R2 to read: "Each Resource Planner and Planning Coordinator shall request verified generating unit Real Power capability data and shall provide each Generator Ownerâ€¦" R1 requires the GO to submit information but it does not indicate to whom the data should be submitted. We recommend that R1 be changed to read: "Each Generator Owner shall verify the summer and winter Real Power generating capability for each of its units in accordance with MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability and record and submit the information to its Resource Planner and Planning Coordinator via MOD-024-2 Attachment 2 - One-line Diagram, Table and Summary for Verification Information Reporting." Paragraph 2.4 in Att 1: The first word grouping is not a sentence and reads awkwardly. It is suggested that the words "an acceptable value can be obtained" be place in front of the words "by making a temperature". Paragraph 3.4.2 in Att 1: Replace the word "since" with "if" for better clarity. Paragraph 3.4.4 in Att 1: Move the words "in Attachment 2" to the position just after the word "flows". This will make it clear that the sentence refers to flows in Attachments 2 rather than units in Attachment 2.
Individual
Dan Rochester
Independent Electricity System Operator

Yes
Accurate data for real power output of a generating unit/plant is critical to system modeling for resource adequacy and transmission reliability analyses. Unless other standards already cover the requirement for this data, this standard needs to be retained but some of the details for the additional empirical data are not necessary. Please see our comments under Q9.
Yes
This is a simple approach that should be supported. Notwithstanding our response and consistent with our reply to Q1, where the provision of this information is already required in other standards, those requirements should not be duplicated here.
Yes
Yes
We do not have any concern with the proposed approach. Individual Regions or markets that identify a need to verify such units to meet local requirements can establish regional specific criteria and market rules as they see appropriate.
Yes
No
We agree with the RPs and PCs to specify the schedule for receiving verified information to suit their needs. However, we have concerns with the applicability which relates to the purpose of the standard. a. The purpose of the existing MOD-024-1 is: â€œTo ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.â€ This implies that the data is also used for accurate modeling of the BES which the TPs, TOPs and RCs use to assess transmission system performance. The purpose of the proposed MOD-024-2 appears to have been changed somewhat: â€œTo ensure that planning entities have accurate generator Real Power capability modeling data used in system planning studies.â€ This change was not mentioned in the SAR for the project (posted for comment in April 2007). We have two concerns with this change and the corresponding requirements: (i) The data is not only used for planning, it is also used for operational planning and near-term adequacy assessments (ii) If the intent of the existing standard is to continue, then the data is used for transmission reliability assessment as well. Other applicable entities need to be added. We suggest the SDT to assess the intended users of the generatorâ€™s real power capability data. Is the data used for resource adequacy assessment only, or is it also used for system model for transmission reliability/adequacy assessment? If it is the former, then RPs and PCs would be the only users. If itâ€™s the latter, then TPs, TOPs, and RCs can be the other users. b. In the Background Information section of the comment form, the SDT indicates that it â€œhas taken the approach that the Transmission Planner needs to communicate the conditions under which the Generator Owner is to provide verified values.â€ The proposed requirement does not include TPs. We wonder if the Background Information quoted the incorrect entities, or the standard is missing the TP as an applicable entity.
No
No
Yes
The detailed requirements in Attachment 1 are overly prescriptive. Specifically, the requirements listed in Item 3 are too detailed, and most of them are not needed for reliability. We believe Attachment 1 needs only to specify the sustainability (Items 1 and 2), periodicity (Item 4) and the ambient conditions of the verification (some of Item 3). Using the form and the one-line diagram do not contribute to reliability. A requirement to ask for both gross and net capability would suffice.
Group
Bonneville Power Administration
Denise Koehn
Yes
BPA suggests reducing the frequency of data collection ... not sure it needs to be every 5 years, it is just more onerous documentation for something that does not change a lot.
Yes
Yes
Yes
It seems like Wind and Solar should do a report for their peak generation for Summer and Winter

on a periodic basis.
Yes
Yes
No
No
Yes
Attachment 2 needs modification: Attachment 2 should have a measurement point on their diagram for the gross generator output, and the table should specify what values to use in the calculation of each column (Gross capability power = new point F, Aux power = A+B+C+D, Net Power = F-A-B-C-D) Because this standard is paired with MOD-025(reactive), BPA believes they should be commented together.
Group
IRC Standards Review Committee
Ben Li
Yes
The SRC agrees that there is a need for a verification requirement. Given that the GOs are responsible for submitting real power data, there should be a corresponding requirement to verify that data on an as-requested basis. This approach provides the Planners with data that is valid for producing viable forecasts and assessments.
No
There is no need for the SDT to impose a requirement / limitation on what is or is not subject to a NERC standard. The FERC has established those boundaries. To the extent that a PC needs or does not need verification of generators that fall outside those FERC-identified conditions, must be justified on a reliability need or settled outside the NERC-standard process.
No
A Planning Coordinator should be afforded the right to request periods other than one continuous hour as needed for ad hoc evaluations e.g. for Ancillary Service evaluations over a 15 minute period or for special case studies e.g. fuel disruption analysis. The default period may be agreed to as one continuous hour but that should not be the mandated period.
No
The SDT should not be concerned with administrative details. The PC should be responsible for requesting verification when verification is needed as opposed to mandating artificial (i.e. one test for all conditions) verification for the sake of artificial verification.
No
The SRC believes with the concept that regular period-specific verification is not necessary, but does not agree with the SDTâ€™s requirement. Rather the SRC would propose that R1 and R2 be replaced by the following 3 requirements: R.1. Each Planning Coordinator that requires validation of a Generator Ownerâ€™s reported generator capability for use in a NERC-mandated assessment shall submit a request to the Generator Owner specifying the applicable conditions. These conditions may include such parameters as: â€¢ Gross or Net data â€¢ Time (season) required â€¢ Boundary conditions (temperature, wind if appropriate) R.2. Each Generator Owner shall verify the Real Power generating capability for each of its units in accordance with requests from their Planning Coordinator. R.3. The Planning Coordinator shall distribute the verified data to the Resource Planners that request the data, or are known by the PC to use that data. Note: CAISO does not support the proposed R3.
No
Yes
Certain Regional Entities are currently developing or have developed standards to comply with MOD-024-1 and close coordination will be necessary to ensure that no compliance conflicts are created with the approval of this updated standard.
No
Group
Calpine Corporation
Duncan Brown
No

The reliability need has not been adequately demonstrated and the standard should be retired. It's not clear that it's necessary to require a high degree of accuracy on one segment of generation, when another segment (variable generation) is not addressed and loads levels used in studies are estimates.
Yes
We agree with the demarcation but recommend it be reworded to exclude generation units interconnected at voltages below 100 kV and units below 20 MVA to avoid unnecessary discussion of registration criteria.
Yes
No
If there's truly a reliability need for verification of capability, this segment of generation needs to be addressed.
Yes
Yes
No
No
Yes
Combined cycle power plants are often built with peaking capability such as steam injection for power augmentation. The term "normal operation" should be defined and include a statement that peaking capability is included only if the unit routinely operates in this mode. Combined cycle plants are sensitive to a variety of ambient conditions in addition to temperature, such as relative humidity. The standard should be revised to include other ambient data required by the generator to adjust output.

Consideration of Comments on the 1st Draft of MOD-024-2 Verification and Data Reporting of Generator Real Power — Project 2007-09 Generator Verification

The Generator Verification Standard Drafting Team thanks all commenters who submitted comments on the 1st Draft of MOD-024-2 Verification and Data Reporting of Generator Real Power — Project 2007-09 Generator Verification. This standard was posted for a 30-day public comments period from January 18, 2010 through February 18, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comments Form. There were 47 sets of comments, including comments from more than 130 different people from over 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

Summary Consideration:

Redundancy: Several commenters indicated that the data addressed in MOD-024-2 is already required to be provided through other standards.

- Considerable time has passed since MOD-024-2 was originally posted, and some of the other standards that previously included data provision requirements have now been proposed for retirement. Some of the duplicate requirements were identified in the TOP series of standards and the TOP requirements have been identified for retirement to avoid duplication with the MOD-024 standard. The requirements slated for retirement include TOP-002 Requirement R 12 which was the closest matching data collection requirement to MOD-024 for real power verification.

The drafting team has reviewed each of the standards identified as possibly containing a requirement redundant with MOD-024 and has confirmed that the proposed requirements in the revised MOD-024 do not duplicate other requirements. To clarify this point the SDT acknowledges that if the correct system operations circumstance exists then the data obtained by performing the Real Power capability verification required by the MOD-024 standard (now incorporated into the MOD-025 standard) for system planning purposes may yield the same results as could be obtained by using equipment nameplate ratings, unit operational data, EMS data, forecast information, etc. required to be provided to the ERO by other standards. Recognize this alternate set of data is collected for other reliability purposes and is not guaranteed to represent actual capability. As such, there is a reliability need to specifically require Real Power capability verification. The SDT also acknowledges it is acceptable to utilize reasonable assumptions when performing long term planning analysis however the SDT also believes it is prudent from a reliability concern to incorporate established unit operational constraints into the planning model when relevant. Units may be derated or constrained for a variety of legitimate long term reasons. Likewise, units derated or constrained today may have restrictions released in the future. Only by performing a Real Power capability verification to determine what the unit is capable of supplying can accuracy of needed reliability data be assured.

Applicability: The requirement for the Resource Planner and Planning Coordinator to provide the Generator Owner with schedules and temperature adjustments was deleted, and the applicability section of the standard was revised to omit the Planning Coordinator and Resource Planner.

Several commenters had specific suggestions for modifications to the proposed applicability, and the drafting team defaulted to using the same facility criteria for generating units as listed in the compliance registration criteria.

Several commenters provided support for including variable units, such as solar wind and run of river hydro, in the real power verification because these units are important to the model of the system, even though they might not reach their maximum real power capability on any given day due to the resource they depend on as a ‘prime mover’. The revised standard does not exempt these units from the verification requirements.

Requirement R1: Several commenters indicated that Requirement R1 didn’t specify where to send the verified data. The requirement was modified to clarify that the data must be sent to the Planning Coordinator. The Functional Model indicates that all planning entities are required to collect data for models, and also indicates that these entities are required to coordinate the update of models with other planning entities. As envisioned, the Planning Coordinator will share the data from the Generator Owner with its Resource Planners and Transmission Planners.

Some commenters suggested that the verified data should be shared with all operating and planning entities and this suggestion was not adopted. The revised standard does not provide the data to any operating entities as the data is verified for its applicability in long-range planning studies, and the data needed for operating monitoring and operational analysis needs to be more current than needed for planning studies.

Several commenters suggested that verifications are not needed every year – and proposed a five year cycle and this was adopted. Seasonal verifications are not included in the revised standard.

The SDT has combined the requirements of MOD-024 and MOD-025 into MOD-025. Under the combined standard, all applicable units will be verified for both real and reactive power capability just once every five years. To avoid having many units requiring verification in any one year, the initial implementation period proposed requires verification of 20% of an entity’s units each year.

Requirement R2: The first draft of MOD-024-2 required the Generator Owner to provide its verified data to both the Planning Coordinator and the Resource Planner according to a schedule defined by the planning entity. The majority of respondents supported having the Resource Planner and Planning Coordinator provide a schedule for performing the verifications which was the SDT’s initial proposal; however, the stakeholder comments indicated that this approach may result in a large number of different schedules, potentially causing confusion among the entities that must provide the data. The SDT has dropped the requirement to have the planning entities provide the Generator Owner with a schedule for conducting verifications since the periodicity for conducting verifications was revised to 5 years.

Requirement R3: The first draft of MOD-024-2 required the Generator Owner to provide the Resource Planner and Planning Coordinator with updates to its verified capabilities when the change to gross Real Power generating capability was expected to last at least six months and involve at least 50 MW. Several comments suggested that the 50 MW threshold should be modified and the SDT has proposed a 10% change to the last verified capability as the threshold in the revised standard. Note that in the revised standard this update is addressed in Attachment 1 and is considered part of Requirement R1.

All persons and entities that have provided comments on MOD-024-2 are encouraged by the SDT to review the first posting of MOD-025-2.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comments serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. MOD-024-1, Verification of Generator Gross and Net Real Power Capability, was approved by the NERC Board 2/7/2006. It has not been approved for enforcement under Section 215 by FERC because it contains "fill-in-the-blank" characteristics with responsibilities assigned to the Regional Reliability Organization. Megawatt data is currently collected and reported under several other standards as well as many market rules. Do you feel that there is a reliability need for this additional empirical data, or should this standard be retired? Please explain. 13

2. The SDT believes that verification should be performed on units that are connected down to 100 kV. The SDT believes this is consistent with the current Compliance Registry. The SDT has also provided how verification should be handled in plants/facilities that are greater than 75 MVA in aggregate gross nameplate rating. The Standard requires a separate verification for every unit greater than 20 MVA gross nameplate rating and connected at the point of interconnection of 100 kV or above. The remaining units in a plant/facility can be verified separately or in aggregate as the Generator Owner chooses. Do you agree with the SDT's decision to have the Standard be applicable to facilities connected to 100 kV and above and verified as proposed? Please explain. 29

3. After much discussion the SDT decided to require the verification be performed over a period of at least "one continuous hour" regardless of the type of unit because most units have reached steady state operation within one hour. Do you agree with this approach? If not, please explain. 37

4. The SDT felt that units that cannot sustain continuous operation, oftentimes known as intermittent, variable or limited energy units, such as a Wind Generating Station or run-of-river hydro, etc., should be exempt from this standard because such units are typically represented in studies with "on average" or "discounted" values. Do you agree with this approach? If not, please explain. 45

5. The SDT has developed a separate periodicity approach for identical units at the same site in Number 4.4 of Attachment 1. The Generator Owner would only be required to verify 20% of these units per year. Do you agree with this approach? If not, please explain. 53

6. The SDT believes that every Resource Planner and Planning Coordinator does not necessarily perform studies involving generating unit verified capability at the same time each year nor do they necessarily need current verified information at the same time. The SDT has developed Requirement R2 that requires the Resource Planner and Planning Coordinator to provide a schedule for receiving verified information that best fits the schedule and needs for performing studies. Do you agree with this approach? If not, please explain. 59

7. Are you aware of any regional variances that would be required for this standard? 69

8. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? 75

9. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please provide a reference to the section, requirement or

subrequirement that you believe should be changed, added or deleted and the rationale for your proposal. 80

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

	Commenter		Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
8.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
9.	Brian L. Gooder	Ontario Power Generation Inc.	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick System Operator	NPCC	2
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

2. Group Thomas J Bradish Generators Supporting Elimination of MOD-024 X X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Fishman	AES Warrior Run	NPCC	5
2.	Benjamin Church	NextEra Energy Resources, LLC	TRE	5
3.	Steve Toth	Covanta, Fairfax, Inc.	RFC	5
4.	David Murray	Guadalupe Power Partners LP	NPCC	5
5.	Rheal Caron	GDF SUEZ Energy Marketing NA, Inc.	NPCC	6
6.	Steve Kimmish	PSEG Energy Resources & Trade LLC	NPCC	6
7.	Angie McCarroll	Valencia Power, LLC	WECC	5
8.	Harry Brand	Rensselaer Cogeneration, LLC	NPCC	5
9.	Gary L. Carlson	Michigan Public Power Agency	RFC	5
10.	Michelle D'Antuono	Occidental Chemical Corporation	SERC	5
11.	Gina Navarro	NAEA Energy Massachusetts, LLC	NPCC	5
12.	Mary Jo Cooper	Canandaigua Power Partners II, LLC	WECC	5
13.	Larry Rodriguez	Union Power Partners, L.P. (PUPP)	SERC	5
14.	Kelsi Jo Oswald	Pinellas County Resource Recovery	NPCC	5
15.	Larry Rodriguez	Gila River Power, LP - GO/GOP/PSE	WECC	5, 6

3. Group Carol Gerou NERC Standards Review Subcommittee X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Lawrence	American Transmission Company	MRO	1
2.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
3.	Terry Bilke	Midwest ISO Inc.	MRO	2
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4

6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

4.	Group	Howard Rulf	We Energies			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dale Fredrickson	We Energies	RFC	3, 4, 5
2.	Jeff Klarer	We Energies	RFC	

5.	Group	Mike Garton	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jalal Babik	Dominion Resources, Inc.	SERC	1
2.	Louis Slade	Dominion Resources, Inc.	RFC	6
3.	Chip Humphrey	Dominion Resources, Inc.	RFC	5
4.	Fatima Ahmed	Dominion Resources, Inc.	RFC	5
5.	Jeffrey Heffelman	Virginia Electric & Power Company - Fossil & Hydro	SERC	5
6.	Matthey Woodzell	Virginia Electric & Power Company - Fossil & Hydro	SERC	5
7.	Larry Whanger	Virginia Electric & Power Company - Fossil & Hydro	SERC	5
8.	Lou Nunez	Dominion Resources, Inc.	NPCC	5

6.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Mike Williams	FE	RFC	5
3.	Bill Duge	FE	RFC	5
4.	Brian Orians	FE	RFC	5
5.	Dave Folk	FE	RFC	1, 3, 4, 5, 6

7.	Group	Jose Medina (NextEra-GS Chair)	SERC Generation Subcommittee (GS)										X

Please complete the following information.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brad Haralson	AECI	SERC	
2.	Paul Camilletti	Santee Cooper	SERC	
3.	Dale Goodwine	Duke Energy	SERC	
4.	Terry Crawley	Southern Co.	SERC	
5.	Tom Higgins	Southern Co.	SERC	
6.	Robin Siewert	E.ON US	SERC	
7.	Chris Georgeson	Progress Energy	SERC	
8.	Kumar Mani	Progress Energy	SERC	
9.	Sam Dwyer	Ameren	SERC	
10.	Travis Borrini	Ameren	SERC	
11.	Chris Schaeffer	Duke Energy	SERC	
12.	Joe Spencer	SERC Reliability	SERC	

8.	Group	Frank Gaffney	Florida Municipal Power Agency and Some Members	X		X	X	X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5
2.	Greg Woessner	Kissimmee Utilities Authority		1, 3, 5

9.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	X		X		X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Co.	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	John Harmon	Midwest Independent Transmission System Operator, Inc.	SERC	1
4.	James Manning	North Carolina Electric Membership Corporation		3
5.	Pat Huntley	SERC Reliability Corporation		10
6.	Bob Jones	Southern Company Services, Inc. - Transmission		1

10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	BPA, Transmission, Technical Services	WECC	1

11.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	James Castle	NYISO	NPCC	2
3.	Bill Phillips	MISO	MRO	2
4.	Lourdes Estrada-Salinero	CAISO	WECC	2
5.	Steve Myers	ERCOT	ERCOT	2
6.	Charles Yeung	SPP	SPP	2
7.	Mark Thompson	AESO	WECC	2
8.	Matt Goldberg	ISO-NE	NPCC	2

12.	Individual	Duncan Brown	Calpine Corporation					X					
13.	Individual	Silvia Parada Mitchell	GO/GOP					X					
14.	Individual	David P Belanger	Exelon Generation Co LLC					X					
15.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
16.	Individual	Rick Terrill	Luminant					X					
17.	Individual	Jack Cashin	Electric Power Supply Association (EPSA)					X					
18.	Individual	Stephen Mizelle	Southern Company Transmission/Generation					X					
19.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
20.	Individual	Ray Phillips	AMEA				X						
21.	Individual	Scott McGough	Oglethorpe Power Corporation					X					
22.	Individual	Martin	Bauer					X					
23.	Individual	Jonathan Appelbaum	Long island power Authority	X									

24.	Individual	Russell A. Noble	Cowlitz County PUD			X			
25.	Individual	Edwin Thompson	Consolidated Edison Co. of New York	X		X		X	X
26.	Individual	Baj Agrawal	Arizona Public Service Co.	X					
27.	Individual	Greg Mason	Dynegy Inc					X	
28.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X
29.	Individual	Kenneth D. Brown	Public Service Electric and Gas Company	X		X			
30.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X
31.	Individual	Marty Berland	Progress Energy	X		X		X	X
32.	Individual	Scott Berry	Indiana Municipal Power Agency				X		
33.	Individual	Armin Klusman	CenterPoint Energy	X					
34.	Individual	Greg Rowland	Duke Energy	X		X		X	X
35.	Individual	Jason Shaver	American Transmission Company	X					
36.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X
37.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X
38.	Individual	Richard Kafka	Pepco Holdings, Inc	X		X		X	X
39.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X					
40.	Individual	Michael Ayotte	ITC Holdings	X					
41.	Individual	Joylyn Faust	Consumers Energy			X	X	X	
42.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X	

43.	Individual	Fred Meyer	The Empire District Electric Company	X		X		X					
44.	Individual	Laura Zotter	ERCOT ISO		X								X
45.	Individual	Catherine Koch	Puget Sound Energy	X									
46.	Individual	James Manning, Bob Beadle, Dave Sofra	North Carolina Electric Membership Corporation			X	X	X	X				
47.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. **MOD-024-1, Verification of Generator Gross and Net Real Power Capability, was approved by the NERC Board 2/7/2006. It has not been approved for enforcement under Section 215 by FERC because it contains "fill-in-the-blank" characteristics with responsibilities assigned to the Regional Reliability Organization. Megawatt data is currently collected and reported under several other standards as well as many market rules. Do you feel that there is a reliability need for this additional empirical data, or should this standard be retired? Please explain.**

Summary Consideration:

The intent of question 1 was to obtain input from industry as to whether MOD-024 was required to ensure reliability, or should it be retired because real power data is collected and reported under other NERC standards and market rules. The originally proposed MOD-024-2 had three requirements:

- R1 required the Generator Owner to verify summer and winter real power generating capability of each of its units
- R2 required the Resource Planner and Planning Coordinator that wanted verified generating unit real power capability data to provide the Generator Owner with temperature adjustments and a schedule for verification
- R3 required the Generator Owner to report significant changes in gross Real Power generating capability to its Resource Planner and Planning Coordinator

There was a mixture of responses indicating to the Standard Drafting Team (SDT) that the question had been interpreted differently by different commenting entities. In hindsight, the question was worded poorly.

Stakeholders indicated that the following standards include requirements that duplicate the requirements the SDT had originally proposed with MOD-024:

FAC-002-0, Requirements R1 and R1.1 and R1.4

- The requirements identified require evidence of coordination in conducting studies before integrating facilities. The requirements do not require identification or sharing of specific capability data.

FAC-008/009

- FAC-008-1 requires the facility owner to document and share its facility rating methodology – it does not require sharing any facility ratings
- FAC-009-1 requires the facility owner to develop and communicate its facility ratings. The facility rating is not the same as the capability.

TOP-002, Requirement R12/R13, R14 and R15

- Requirement R13 requires the Generator Operator to perform real and reactive power capability verifications, but this requirement has been proposed for retirement under Project 2007-03 to avoid duplication with MOD-024.
- Requirement R14 requires the Generator Operator to notify the Balancing Authority of changes in capabilities and characteristics. This requirement involves different functional entities for both reporting and receiving data – it has a different reliability objective from MOD-024-2 (now MOD-025).
- Requirement R15 has been proposed for retirement under Project 2007-03.

TOP-003, Requirements R1, R2, and R3

- Requirements R1, R2, and R3 are all related to sharing of outage information. Requirement R3 from the originally proposed MOD-024-2 has been modified and absorbed in the attachment associated with Requirement R1 of MOD-025. Now outage information that leads to different real or reactive power capability only needs to be reported if the outage changes the capability by at least 10% for at least 6 months. The drafting team working on TOP-003 has proposed modifications that eliminate requirements to provide specific data – the revised standard, as proposed, allows each TOP to identify what data it needs and to request that data from the entities that have that data. Neither the original TOP-003 nor the proposed revisions to TOP-003 address provision of the same data to the same entities as the data proposed to be provided by the Generator Owner to the Resources Planner and Transmission Planner in MOD-024 (now MOD-025.)

TOP-006, Requirements R1 and R1.1

- Requirements R1 and R1.1 in TOP-006 do not duplicate the proposed requirements in MOD-024 (now MOD-025). The requirements in TOP-006 require the TOP to 'know' the status of generation resources available for use – and require the Generator Operator to provide the Transmission Operator with that information. The requirements in TOP-006 are intended for exchange of information for near real-time use, and don't involve the same data or the same entities as proposed to be provided in MOD-024 (now MOD0-025).

MOD-010/011

- MOD-011 Requirement R1.2 does require the RRO to develop a specification for entities to provide net generator minimum and maximum Ratings for both real and reactive power and MOD-010 does require the Generator Owner to provide the requested data. The minimum and maximum ratings are not the same as the capabilities.

MOD-012, R1

- MOD-012, Requirement R1 requires Generator Owners to provide equipment characteristics to the Regional Reliability Organization, which is not the same as providing unit capabilities collected under specific conditions.

MOD-026/027

- MOD-026-1 requires Generator Owners to provide generator excitation control system and plant volt/var control function models to accurately represent control response behavior during dynamic simulation, which is reactive power response behavior.
- MOD-027-1 requires Generator Owners to provide turbine/governor and load control or active power/frequency function models to accurately represent control response behavior during dynamic simulation, which is not the same as Real Power capabilities.

Please see the proposed revisions to MOD-024 that have been absorbed into MOD-025. The changes allow use of historical data; merge the requirements for the two standards into a single standard for efficiency when conducting the verifications.

Organization	Yes or No	Question 1 Comment
SERC Generation Subcommittee (GS)		The SERC Generation Subcommittee (GS) could not answer this definitively yes or no. The GS believes that reporting on MOD-024 is duplicative with other standards and may be retired. While this data is important, it is covered under:FAC-008/009, TOP-002, MOD-010/011, etc.
Response: Thank you for your comments. Please see the summary consideration. The drafting team reviewed FAC-008/009, TOP-002 and MOD-010/MOD011 as well as other standards for potential duplication and did not find duplication with the proposed requirements. After thorough consideration of all responses and additional deliberation, the SDT is proposing that the revised standard require the Generator Owner to collect real power verification data at the same time as reactive power verification data, and merged MOD-024 requirements in MOD-025. To perform the reactive power verification it is necessary to go to the rated real power operating point. Therefore, recording and reporting both the real and reactive power data as part of the MOD-025 verification only makes sense for efficiency.		
American Electric Power	No	
ITC Holdings	No	
PacifiCorp	No	: Information required under the proposed standard is currently submitted with FERC Form 1 and for FAC-008 compliance. This standard is redundant and should be retired.
Response: Thank you for your comments. Data provided under FERC Form 1 is not required to be shared with entities that need the data for modeling. FAC-008-1 does not require sharing of capabilities, it requires developing a facility rating methodology. FAC-009 requires sharing of facility ratings developed according to the rating methodology, however facility ratings are not the same as capabilities.		
Indiana Municipal Power Agency	No	IMPA is anwering no to the question "Do you feel that there is a relaiblity need for this additional empirical data", and answering yes to the question "should this standard be retired". The reporting of megawatt data in

Organization	Yes or No	Question 1 Comment
		other reliability standards and in market testing requirements for units is enough.
Response: Thank you for your comments. Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements. Data provided under FERC Form 1 is not required to be shared with entities that need the data for modeling. **After thorough consideration of all responses and additional deliberation, the SDT is proposing that the revised standard require the Generator Owner to collect real power verification data at the same time as reactive power verification data, and merged MOD-024 requirements in MOD-025. To perform the reactive power verification it is necessary to go to the rated real power operating point. Therefore, recording and reporting both the real and reactive power data as part of the MOD-025 verification only makes sense for efficiency.**		
GO/GOP	No	No, we do not feel additional empirical data is necessary as we believe this version should include data required in Version 1 as this version gave a better description of what is happening with a generating unit during a test. Yes, we do feel this standard should be retired. We believe this standard is unnecessary since real power verification can and should be handled by generation and transmission agreements. The Generator Owner (GO) & Generator Operator (GOP) provide generation unit real power capability in seven standards other than in MOD-024 plus the Transmission Operator (TOP), Reliability Coordinator (RC), Balancing Authority (BA) and Regional Transmission Organization (RTO) / Independent System Operator (ISO) see a unit's real time output via their Energy Management System (EMS). Therefore, the generator testing and reporting contemplated under MOD-024 is unnecessary. In addition, MOD-026 and 027 have not been considered in this discussion but are anticipated to be approved over the course of the next two years would cause further duplication. Thus, MOD-024 is clearly unnecessary.
Response: Thank you for your comments. Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements. Note that the standard was modified and the second draft does allow use of historical data from actual output.		
Bauer	No	The changes in this standard duplicate and conflict the requirement specific under TOP002. Originally this standard was for verification procedures which were used to meet TOP-002. The verification procedures defined in this standard should be incorporated into TOP-002 if this standard is retired.
Response: Thank you for your comments. TOP-002-2a Requirement R13 requires the Generator Operator to perform real and reactive power capability verifications, but this requirement has been proposed for retirement under Project 2007-03 to avoid duplication with MOD-024. Please see the summary consideration.		
Generators Supporting	No	The generator owner/operator provides unit real power capability in six standards other than in MOD-024 plus the TOP/RC/BA/ISO see a unit's real time output via their EMS. MOD-024 is duplicative and, as such,

Organization	Yes or No	Question 1 Comment
Elimination of MOD-024		unnecessary. Planners on the RFC MOD-024 draft standard drafting team argued that they needed to know what a unit could consistently produce over a 7-24 hour period when running their reliability models. They were not interested in knowing short-term unit capability. Another reason for not using the unit's output under a stressed condition is that it is not at a level of reliable output. A unit can generate the real power during a test but many times not under actual system conditions. These tests are conducted at the most favorable time for unit performance and are only indicative of unit performance at that point in time. They are no guarantee of future performance. This results in system operators not getting the real power output that they thought was available to them. This shortage of real power occurs during system emergencies when system operators need the mega-watts the most. Because of this, these mega-watts have been called paper mega-watts. Requiring a test actually fosters a situation counter to ALR.Every unit's output must be metered and its output is monitored in real time in the TOP, RC and/or ISO Energy Management System (EMS). The EMS would have a history of a units output. This data is the most accurate representation of a unit's capability under actual system conditions and is a true representation of actual unit capability. This actual unit production data can be made available to the transmission planners. The transmission planners can analyze EMS data and use that period of unit performance that meets their requirements. If they are interested in a unit's performance during the period of highest demand, they can analyze unit output during the most recent or previous peak demand period. By using actual data, the paper mega-watt's issue goes away. If the planner has any issues, they can discuss these directly with the generator operator/owner.Requiring the planner to analyze EMS data may have another benefit. It will force the planner to become more engaged and communicate more strongly with the real-time system operators. The planner will become more aware of real-time issues that will enable them to incorporate these anomalies into their system models.Another benefit to using actual unit data is that it will eliminate running the unit to perform the MOD-024 verification. Not having to run a unit that is not needed to meet system demand will result in fewer emissions and fuel consumption yielding a higher level of environmental stewardship. As a nation, we are supposed to be concerned about greenhouse gases and efficient use of carbon-based fuels. Forcing units to run is contrary to these national goals.Unit real power capability is specified in the units interconnection agreement with the TO. The GOP is required to report unit de-rates to the TOP, RC, BA or ISO immediately after they occur. Real power reporting requirements currently appear in six (6) standards as follows: FAC-002-0: R1. The GO, TO, Distribution Provider (DP), and Load-Serving Entity (LSE) seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include: R1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

Organization	Yes or No	Question 1 Comment
		R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0. MOD-010-0 Applicability 4.3. GO specified in the data requirements and reporting procedures of MOD-011-0 R1. MOD-011-0 R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status. TOP-002-2a R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested. R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007) R14.1. Changes in real output capabilities. (Effective August 1, 2007) R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output). TOP-003-1 R1. Generator Operators and Transmission Operators shall provide planned outage information. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection. R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series

Organization	Yes or No	Question 1 Comment
		capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required. R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas. TOP-006-2 R1` Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. R1.1 Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. Because the generator owner/operator provides unit real power capability in six standards plus the TOP/RC/BA/ISO see a unit's real time output via their EMS reporting the generator testing and reporting contemplated under MOD-024 is unnecessary. In addition, MOD-026 and 027 have not been considered in this discussion but are anticipated to be approved over the course of the next two years would cause further duplication. Thus, MOD-024 is clearly unnecessary.

Response: Thank you for your comments. The revised MOD-025 (which includes Requirement R1 from the originally proposed MOD-024-2) does allow the use of operational data.

The SDT acknowledges that if the correct system operations circumstance exists then the data obtained by performing the Real Power capability verification required by the MOD-024 standard (now incorporated into the MOD-025 standard) for system planning purposes may yield the same results as could be obtained by using equipment nameplate ratings, unit operational data, EMS data, forecast information, etc. required to be provided to the ERO by other standards. Recognize this alternate set of data is collected for other reliability purposes and is not guaranteed to represent actual capability. As such, there is a reliability need to specifically require Real Power capability verification. The SDT also acknowledges it is acceptable to utilize reasonable assumptions when performing long term planning analysis however the SDT also believes it is prudent from a reliability concern to incorporate established unit operational constraints into the planning model when relevant. Units may be derated or constrained for a variety of legitimate long term reasons. Likewise, units derated or constrained today may have restrictions released in the future. Only by performing a Real Power capability verification to determine what the unit is capable of supplying can accuracy of needed reliability data be assured.

Requiring a one hour capability test period is based on engineering judgment. The SDT envisions Generator Owners will first realize steady state conditions at maximum capability before commencing the one hour verification test. The SDT believes demonstrating a unit can operate at maximum capability during steady state conditions for one hour also proves the unit can operate indefinitely in this manner. Also, the proposed PRC-024-1 standard requires generator performance by remaining connected during voltage and frequency excursions.

The SDT agrees in general with comments raised regarding environmental stewardship concerns and believes this consideration is rendered moot by requiring verification once every five years. It is reasonable to assume that the unit will run for at least one hour at maximum capability during the five

Organization	Yes or No	Question 1 Comment
year period. **Please see the summary consideration. The drafting team reviewed each of the standards and requirements you've identified for potential duplication and did not find duplication with the proposed requirements. Note that the standard was modified and the second draft does allow use of historical data from actual output.**		
Calpine Corporation	No	The reliability need has not been adequately demonstrated and the standard should be retired. It's not clear that it's necessary to require a high degree of accuracy on one segment of generation, when another segment (variable generation) is not addressed and loads levels used in studies are estimates.
Response: Thank you for your comment. The reliability-related need for this project was established at the SAR development stage of this project.		
Hydro-Quebec TransEnergie (HQT)	No	The SDT is asking two question at the same time, with possible contradicting answer.There is reliability need to collect this data. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards. If it is, the Standard (MOD-024) should be retired. If it is not done in other Standards this project should be pursued. Even if the collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements, in what way would the compliance and sanction be addressed? If there is a Standard that make it obligatory to respect tariffs, Market Rules, and Interconnection Agreements, this project could be retired.
Response: Thank you for your comments. Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements. After thorough consideration of all responses and additional deliberation, the SDT is proposing that the revised standard require the Generator Owner to collect real power verification data at the same time as reactive power verification data, and merged MOD-024 requirements in MOD-025. To perform the reactive power verification it is necessary to go to the rated real power operating point. Therefore, recording and reporting both the real and reactive power data as part of the MOD-025 verification only makes sense for efficiency.		
Exelon Generation Co LLC	No	The standard should be retired there is presently an number of different standards the require Generators to provide the same information.
Response: Thank you for your comment. Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements.		
Public Service Electric and Gas Company	No	The standard should be retired. There are several other standards pursuant to which the GO and/or GOP provides real power capability to those parties needing that data. Also, the RTOs, ISOs, in their role as TOP,

Organization	Yes or No	Question 1 Comment
		RC and BA receive actual data continuously via the EMS. Likewise, those entities performing the same functions in non-ISO areas also receive the data. The actual operating data collected through EMS systems is far superior in quality to that resultant from compliance with MOD-024, both presently and as proposed. Imposing duplicate burdens on generators with no commensurate benefit to reliability should be avoided. Hence, MOD-024 is not necessary.
Response: Thank you for your comments. Keep in mind ambient monitoring is allowed and EMS system data does not necessarily represent unit maximum capability. The SDT acknowledges that if the correct system operations circumstance exists then the data obtained by performing the Real Power capability verification required by the MOD-024 standard (now incorporated into the MOD-025 standard) for system planning purposes may yield the same results as could be obtained by using equipment nameplate ratings, unit operational data, EMS data, forecast information, etc. required to be provided to the ERO by other standards. Recognize this alternate set of data is collected for other reliability purposes and is not guaranteed to represent actual capability. As such, there is a reliability need to specifically require Real Power capability verification. The SDT also acknowledges it is acceptable to utilize reasonable assumptions when performing long term planning analysis however the SDT also believes it is prudent from a reliability concern to incorporate established unit operational constraints into the planning model when relevant. Units may be derated or constrained for a variety of legitimate long term reasons. Likewise, units derated or constrained today may have restrictions released in the future. Only by performing a Real Power capability verification to determine what the unit is capable of supplying can accuracy of needed reliability data be assured. **Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements. Note that the standard was modified and the second draft does allow use of historical data from actual output.**		
AMEA	No	The two questions the SDT asked on question 1 could have two different answers. I answered no to the additional data and yes to retire this standard.The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
Response: Thank you for your comment. The generators covered by this standard are those that are owned by Generator Owners required to register for compliance.		
Arizona Public Service Co.	No	There is no reliability need for this standard and it should be retired. It does not serve any purpose and no body uses this data.
Response: Thank you for your comment. The reliability-related need for this standard was established with the SAR for this project. The data is used in models that are then used to conduct assessments of the bulk power system.		
South Carolina Electric and Gas	No	This standard appears to be redundant with TOP-002 R13. Also, Generator ratings are established in FAC-008. If a verification run by MOD-024-2 contradicts a rating established in FAC-008, which rating should an entity use? If the rating established by verification were used, would this not alter an entity's facility rating

Organization	Yes or No	Question 1 Comment
		methodology?
Response: Thank you for your comments. Please see the summary consideration. Generator ratings are not the same as capability. Actual capability can differ from generator rating provided because of derate or constraint conditions. Furthermore, a unit limited today may be released for unrestricted operation in the future. Capability verification identifies actual unit performance that can be achieved with respect to the operational and regulatory constraints existing. The drafting team reviewed several standards for potential duplication, including TOP-002 and FAC-008 and did not find duplication with the proposed requirements.		
The Empire District Electric Company	No	This standard should be retired
Response: Thank you for your comment. A Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements. Therefore, this standard will not be retired – instead the requirements have been clarified and merged into MOD-025.		
Electric Market Policy	No	We agree that a standard for Verification of Generator Gross and Net Real Power Capability is needed. We support the data being requested in standard MOD-024-2, Attachment 1 and 2.
Response: Thank you for your supportive comment.		
We Energies	No	We feel this requirement could be retired do to the fact that the data is collected and reported under several other standards as well as many market rules. For example, the Midwest ISO has established testing requirements for generators under Module E of the Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff. We also feel that having multiple different testing and reporting requirements can potentially lead to confusion and errors in reporting. If it is determined to not retire this standard, a provision should be made that if generator testing information is provided to a RTO following prescribed testing standards of the RTO, the submittal of the information to the RTO would meet the requirements of MOD-024-2. There is also a concern regarding the different applicability requirements between MOD-024-2 (Generator Owner, Planning Coordinator, and Resource Planner) and the recently passed MOD-024-RFC-01 (Generator Operator and Planning Coordinator) which further illustrates the problem of consistency of requirements.
Response: Thank you for your comments. Data provided under market rules is not necessarily required to be provided to the planning entities that need this data for modeling. Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements. **The drafting team consulted with the Functional Model for verification that the Generator Owner is the correct functional entity to provide data about**		

Organization	Yes or No	Question 1 Comment
its facilities. The Functional Model does not provide as much clarity on responsibility for updating models. The Functional Model assigns all three of the planning entities - the Planning Coordinator, Resource Planner and Transmission Planner with responsibility for collecting data to update models, and assigns all three of the planning entities with responsibility for coordinating data collection with other planning entities. To minimize the efforts associated with providing data, the SDT revised the standard so that the Generator Owner is only required to provide data to the Planning Coordinator.		
Southern Company Transmission/Generation	No	We feel this standard is unnecessary since real power verification can and should be handled by generation and transmission agreements. Most traditional utilities already have a process in place to validate and/or certify unit capabilities. In the case of an IPP, this requirement can be addressed in the Transmission Interface documents. If this standard moves forward, then TOP-002-2 R13 must be deleted or at a minimum, revised to indicate that it addresses short term equipment issues in the operations horizon.
Response: Thank you for your comments. Please see the summary consideration. The drafting team reviewed several standards, including TOP-002, for potential duplication and did not find duplication with the proposed requirements.		
Consumers Energy	Yes	
Long island power Authority	Yes	
Independent Electricity System Operator	Yes	Accurate data for real power output of a generating unit/plant is critical to system modeling for resource adequacy and transmission reliability analyses. Unless other standards already cover the requirement for this data, this standard needs to be retained but some of the details for the additional empirical data are not necessary. Please see our comments under Q9.
Response: Thank you for your supportive comment. Please see the summary consideration. After thorough consideration of all responses and additional deliberation, the SDT is proposing that the revised standard require the Generator Owner to collect real power verification data at the same time as reactive power verification data, and merged MOD-024 requirements in MOD-025. To perform the reactive power verification it is necessary to go to the rated real power operating point. Therefore, recording and reporting both the real and reactive power data as part of the MOD-025 verification only makes sense for efficiency.		
Bonneville Power Administration	Yes	BPA suggests reducing the frequency of data collection ... not sure it needs to be every 5 years, it is just more onerous documentation for something that does not change a lot.
Response: Thank you for your comment. All standards must be reviewed and either reaffirmed or revised once every five years. If, once the requirements are implemented, entities find that the data doesn't change much during a five-year period; the standard can be revised to extend the periodicity beyond five years.		

Organization	Yes or No	Question 1 Comment
ERCOT ISO	Yes	ERCOT ISO believes there is a need for this data. The verification methodologies, including the scheduling and timing of verification testing, should be left to the discretion of the relevant NERC functional entities - e.g. the Planning Coordinator / Transmission Planner.
Response: Thank you for your supportive comment. Please see the summary consideration. After thorough consideration of all responses and additional deliberation, the SDT is proposing that the revised standard require the Generator Owner to collect real power verification data at the same time as reactive power verification data, and merged MOD-024 requirements in MOD-025. Some degree of specificity is necessary to ensure that the data can be used as intended.		
Manitoba Hydro	Yes	If FAC-008 and FAC-009 are based upon design data and Engineering Analysis, a standard is required to complete field verification of the unit real power capability. There should be clear distinctions between these standards.
Response: Thank you for your comment. Agree.		
Luminant	Yes	Luminant believes the verification of capability is needed to ensure unit capabilities utilized for resource planning, operating reserves and real time operations are accurate. “Paper Megawatts” can have a detrimental effect on grid reliability.
Response: Thank you for your comment. Agree.		
Puget Sound Energy	Yes	Note: The way the question is worded with two opposite ideas makes it difficult to determine which box to check. Puget Sound Energy feels that this standard should be retired. This standard duplicates information required by other standards, including MOD-010, MOD-012, TOP-002 (R13), as well as FAC-009. Our Transmission Planners already request temperature related Real Power information for generating units through these other standards. Unit derates (proposed R3) are covered under TOP-002 R14, TOP-003, and TOP-006 R1.1. These other standards allow the Transmission Planners to customize their verification needs from the GO/GOP and not have a one-size fits all solution imposed on them as prescribed in this proposed standard.
Response: Thank you for your comments. Please see the summary consideration. The drafting team reviewed several standards (including MOD-010, MOD-012, TOP-002, TOP-006, and FAC-009) for potential duplication and did not find duplication with the proposed requirements. Note that the standard was modified and the second draft does allow use of historical data from actual output. The intent in MOD-024 (now integrated into MOD-025) is to ensure that planning entities have the data they need for accurate models.		

Organization	Yes or No	Question 1 Comment
E.ON U.S.	Yes	obtaining the additional empirical data is helpful. The data required in Version 1 as established by the Regions gives a better description of what is happening with a generating unit during a test; this version only requires capability, auxiliary power usage, and temperatures-which does not give one a picture of what is occurring during a test and why the capabilities might have been the way they were.
Response: Thank you for your comments. Agree that obtaining the data is helpful to reliability. The original standard was not approved by FERC because the details associated with the verifications were developed by each Region. Please see the revised standard and see if you believe additional information should be collected with the verifications.		
Pepco Holdings, Inc	Yes	Planning Coordinators and Planning Authorities need the data
Response: Thank you for your comment. Agree.		
Dynegy Inc	Yes	Planning related entities (i.e. Planning Coordinator, Resource Planner and Transmission Planner) need the maximum (normalized)demonstrated capability of generating units for inclusion in their planning models. No other Standard requires this data to be accumulated and reported to these entities. Also, historical EMS data that reflects economic dispatch and regulating requirements is not an alternative source for this data.
Response: Thank you for your comments. Agree that planning entities need the data identified in the MOD-024 standard (now integrated into MOD-025). Please see the revised standard – the drafting team is proposing to accept the use of some historical data provided it meets specific criteria.		
NERC Standards Review Subcommittee	Yes	Please review the possibility of redundancy within the following NERC standards: FAC-001-0; R1.1, Connection requirements for Generation facilitiesR2.1.3, Voltage level and MW and MVAR capacity or demand at point of connection. FAC-008-1;R1, GO shall each document its current methodology used for determining Facility Ratings...FAC-009-1;R1, GO shall each establish Facility ratings...MOD-010-0;R1, GOPs shall provide this steady-state modeling and simulation data...MOD-012-0;R1, GOPs shall provide appropriate equipment characteristics and system data...TOP-002-2a;R14, GOP shall notify the BA and TOP of changes in capabilities and characteristics...R14.1, Changes in real output capabilities
Response: Thank you for your comments. Please see the summary consideration. The drafting team reviewed several standards (including FAC-001, FAC-008, FAC-009, MOD-010, MOD-012 and TOP-002) for potential duplication and did not find duplication with the proposed requirements.		
Northeast Utilities	Yes	Standard should be retired.The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the

Organization	Yes or No	Question 1 Comment
		collection of this data is incorporated in existing standards projects.
Response: Thank you for your comments. Data provided under FERC Form 1 is not required to be shared with entities that need the data for modeling. **Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements.**		
Northeast Power Coordinating Council	Yes	The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
Response: Thank you for your comments. Data provided under FERC Form 1 is not required to be shared with entities that need the data for modeling. Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements.		
American Transmission Company	Yes	The requirements of this standard will provide empirical data that will improve system reliability.
Response: Thank you for your comment. Agree. This is the intent of the standard.		
IRC Standards Review Committee	Yes	The SRC agrees that there is a need for a verification requirement. Given that the GOs are responsible for submitting real power data, there should be a corresponding requirement to verify that data on an as-requested basis. This approach provides the Planners with data that is valid for producing viable forecasts and assessments.
Response: Thank you for your supportive comments. The revised MOD standard (now incorporated into MOD-025) provides a schedule for verifying the data that seems reasonable to both the Generator Owner and the recipients of the data. In most cases, the periodicity for verifications is once every five years.		
Florida Municipal Power Agency and Some Members	Yes	There are two potential reasons for the need to test generator capability related to the standards: 1) MOD-010-0 for accuracy of modeling purposes; and 2) for a potential standard on resource adequacy in the planning horizon (Project 2009-05?).
Response: Thank you for your comments. The reliability-related intent of the MOD-024 requirements is to ensure that planning entities have data for accurate models used to assess the bulk power system. MOD-010 and MOD-011 are focused on the maximum and minimum ratings, which do not		

Organization	Yes or No	Question 1 Comment
necessarily match capabilities. The data verified in the MOD-024 standard (now incorporated in the MOD-025 standard) may be used for resource adequacy studies.		
Consolidated Edison Co. of New York	Yes	There is a need to test the gross and net real power capability because it is a key operating and planning horizon requirement to maintain system reliability. Unit testing is critical to System Operations and their ability to respond to contingencies. Even now, there are concerns with interconnection frequency responses and units not responding to AGC signals as noted in the 2-11-2010 NERC Industry Advisory on interconnection frequency response. In addition, as more and more wind generation is installed, generation capability issues will become more important to System Operators. The standard should not be retired, but the requirements should be incorporated into a new FAC standard or included in FAC-008.
Response: The SDT appreciates your comments and concerns. Frequency response is outside the scope of this standard. The standard requires recording data so that the planner will have both net and gross Real Power generation values. The FAC-008 standard is focused on developing a Facility Rating methodology – which is different from identifying a unit's actual capability.		
SERC Planning Standards Subcommittee	Yes	There is a reliability need to verify real power capability for larger units on the system as discussed in our response to Question 2 below.
Response: Thank you for your comment. The drafting team attempted to limit applicability to those units that do affect reliability of the BES.		
FirstEnergy	Yes	We believe that there is a need for this standard. The argument that "megawatt data is currently collected and reported under several other standards as well as many market rules" is not well founded. All Standard Drafting Teams assigned to revise existing standards that include some form of generator verification are proposing to retire their respective requirements because they intended that MOD-024-2 include these requirements. A specific example is the RTO SDT (Project 2007-03) which has proposed to remove requirements dealing with Real Power generator verification in TOP-002 (R13, R14, and R15) because they believe these requirements should be addressed by this GV SDT. The second part of the argument that these verifications are required by "many market rules" is also problematic because not every entity across the continent participates in a market and market rules are not enforceable Reliability Standard requirements.
Response: Thank you for your comments. Agree. Please see the summary consideration. The drafting team reviewed several standards for potential duplication and did not find duplication with the proposed requirements, in support of your comments.		
Xcel Energy	Yes	We believe there is a reliability need for the Megawatt data collected per this standard and consequently this standard should not be retired.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. Agree.		
Duke Energy	Yes	While data is reported under MOD-010, MOD-024 provides for validation of the data.
Response: Thank you for your comment. Agree.		
North Carolina Electric Membership Corporation	Yes	While we agree that there is a reliability need to verify real power capability for larger units on the system, we are of the opinion that the SDT should direct the verification at units that significantly affect the reliability of the BES.
Response: Thank you for your comment. The drafting team attempted to limit applicability to those units that do affect reliability of the BES.		
Progress Energy	Yes	Yes - there is a reliability need. No, the standard should not be retired.
Response: Thank you for your supportive comment.		
Cowlitz County PUD	Yes	Yes the Standard should be retired. This standard appears to duplicate and complicate FAC-008 and FAC-009. If this standard remains, then should generator rating be removed from FAC-008 and FAC-009?
Response: Thank you for your comment. Please see the summary consideration. The drafting team reviewed several standards (including FAC-008 and FAC-009 for potential duplication and did not find duplication with the proposed requirements.		

2. The SDT believes that verification should be performed on units that are connected down to 100 kV. The SDT believes this is consistent with the current Compliance Registry. The SDT has also provided how verification should be handled in plants/facilities that are greater than 75 MVA in aggregate gross nameplate rating. The Standard requires a separate verification for every unit greater than 20 MVA gross nameplate rating and connected at the point of interconnection of 100 kV or above. The remaining units in a plant/facility can be verified separately or in aggregate as the Generator Owner chooses. Do you agree with the SDT's decision to have the Standard be applicable to facilities connected to 100 kV and above and verified as proposed? Please explain.

Summary Consideration: While most stakeholders who responded to this question indicated support with the proposed applicability, some commenters suggested modifications that would match the compliance registration criteria more accurately, and this suggestion was adopted. The phrase, "connected at point of interconnection" was replaced with "directly connected to the bulk power system".

Generators Supporting Elimination of MOD-024		NA. This standard is not needed for reliability.
Response: Thank you for your comment. Please see the summary response to the first question. The need for entities to provide verified unit capabilities was identified and confirmed with the SAR for this project. There was some question that the requirements in MOD-024 may be duplicated by requirements in other standards, and the drafting team researched the other standards and has determined that there is no duplication. Therefore, the team is moving MOD-024 forward, and is integrating the proposed requirements from MOD-024 into MOD-025.		
CenterPoint Energy	No	CenterPoint Energy disagrees with having this Standard be applicable to all units connected to facilities 100 kV and above. CenterPoint Energy recommends it should only be applicable to units interconnected to Bulk Electric System facilities - not all facilities 100 kV and above are considered to be part of a Bulk Electric System.
Response: Thank you for your comment. Please see the summary consideration. The drafting team now proposes the language, "at the point of interconnection at 100 kV or above", in the latest version of the MOD-025-1 draft standard.		
ERCOT ISO	No	ERCOT ISO disagrees with this aspect of the proposal. Although, as a general matter, the relevant set of supply resources for reliability will be interconnected at 100 kV or greater, that is not an absolute rule. In fact, in the ERCOT Region there is a good amount of generation connected at 69 kV. The SDT should not preclude application of the proposed Standard to supply resources connected to facilities below 100 kV. 100 kV can be the default, but the requirement should provide for adequate flexibility to encompass other supply resources the methodology established by the relevant NERC functional entity includes such resources. Furthermore, this is consistent with the NERC Registry methodology, which accommodates facilities below 100 kV where they are necessary for/affect reliability of the Bulk Electric System.

Response: Thank you for your comments. Regions are free to include other facilities through submission of a request for a variance		
The Empire District Electric Company	No	I believe it is redundant to require both summer and winter ratings. Your summer raitings will be your "worst case" for understanding the maximum equipment output. Requireing winter ratings will only waste money and equipment wear.
Response: Thank you for your comment. The SDT has incorporated the real power verification requirements into the revised MOD-025. In the revised standard, the SDT has eliminated the need for seasonal verification. It is expected that only one periodic verification would be required and other data would be calculated based on that one.		
North Carolina Electric Membership Corporation	No	In general there is no reliability need to verify MW values for small units because they don't significantly affect the reliability of the system. The criteria should be to verify individual units which are at least 100 MVA or larger or aggregates of units which are 100 MVA or larger and units that are connected to the transmission at 200 kV and above unless the generating units have been deemed by the Planning Coordinator as critical to the reliability of the BES. This is similar to what has been proposed in the PRC-023 standard under development. All other generators that do not meet this critieria should be exempt.
Response: Thank you for your comment. The intent was to use the same thresholds as included in the compliance registration criteria.		
SERC Planning Standards Subcommittee	No	In general there is no reliability need to verify MW values for small units because they don't significantly affect the reliability of the system. The criteria should be to verify individual units which are 75 MVA or larger or aggregates of units which are 75 MVA or larger. Also provision could be made for the TP or PC to request verification of units which are smaller than 75 MVA for the rare case in which they do impact the reliability of the system.
Response: Thank you for your comment. The intent was to use the same thresholds as included in the compliance registration criteria.		
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
Response: Thank you for your comment. Please see the response to the comments provided under Question 1		
Consolidated Edison Co. of New York	No	SDT should not make reference to a specific voltage level. The SDT should indicate that verification should be performed on units that are connected to the Bulk Electric System as determined by the Region.
Response: Thank you for your comment. The intent was to use the same thresholds as included in the compliance registration criteria.		

Hydro-Québec TransEnergie (HQT)	No	See answer to Q1.HQT believes that there are some plants/facilities that are not connected to 100 kV but are material to reliability. These facilities should be subject to data collection, be it in this project Standard or in other existing Standards. The importance of generation to reliability is more related to its power than to its connecting voltage.
Response: Thank you for your comments. The regions are free to include other facilities if they see fit by submitting a request for a variance		
AMEA	No	The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.The many of the regions have identified generators connected below 100 kV that are material to the BES and likewise have identified generators connected at or above 100 kV that are not material to the BES.
Response: Thank you for your comment. The regions are free to include other facilities if they see fit by submitting a request for a variance.		
Consumers Energy	No	The MVA ratings should be based on Net Demonstrated Capabilities (NDC) rather than nameplate. There is no correlation between reliability and nameplate ratings.
Response: Thank you for your comment. The intent was to use the same thresholds as included in the compliance registration criteria. The default language for generating units includes the phrase, “nameplate rating.”		
IRC Standards Review Committee	No	There is no need for the SDT to impose a requirement / limitation on what is or is not subject to a NERC standard. The FERC has established those boundaries. To the extent that a PC needs or does not need verification of generators that fall outside those FERC-identified conditions, must be justified on a reliability need or settled outside the NERC-standard process.
Response: Thank you for your comments. The intent was to use the same thresholds as included in the compliance registration criteria for generating units and add the criteria for synchronous condensers, which is not identified in the default registration criteria. If the “facilities” section of the applicability section were limited to only listing the criteria for synchronous condensers, this could have been confusing, thus the criteria for generators was also included.		
Pepco Holdings, Inc	No	There is no need to define what already exists in BES definitions and in the compliance registry rules.
Response: Thank you for your comment. The intent was to use the same thresholds as included in the compliance registration criteria for generating units and add the criteria for synchronous condensers, which is not identified in the default registration criteria. If the “facilities” section of the applicability section were limited to only listing the criteria for synchronous condensers, this could have been confusing, thus the criteria for generators was also included.		

Arizona Public Service Co.	No	There is no need to go down to registry level of 20 MVA. The variation in capacity of these small generators has no measurable impact on the grid planning study results. The studies have onsiderable more uncertainties due to other more significant variables. The minimum size should be 100 MVA for each unit or 250 MVA for a plant.
Response: Thank you for your comments. The intent was to use the same thresholds as included in the compliance registration criteria. 20 MVA is the registry criteria.		
Long island power Authority	No	Units below 100 kV may in the future be registered with NERC under the materiality clause. LIPA suggests relying on the MVA rating only. Additionally, LIPA requests that in the Applicability section a statement clarifying that the point of interconnection may not be a BES element.
Response: Thank you for your comments. The intent was to use the same thresholds as included in the compliance registration criteria. The SDT cannot think of an instance where the interconnection point would not be a BES element. Please see the revised standard.		
Southern Company Transmission/Generation	No	We recommend limiting the unit size requiring real power capability validation in paragraph 4.2 to the following: "Generating Facilities connected at the point of interconnection at 100kV or above, containing an individual generating unit greater than or equal to 75MVA (individual gross nameplate rating)", for the following reasons: o Including only units > 75MVA will represent the vast majority of the total (cumulative) connected MW sources in the country o This cumulative MW class represents the units that are capable of having the largest impact to the stability and reliability of the BES o Excluding the smaller units will avoid unnecessary waste in time and money on the smaller units which individually do not appreciably affect the stability and reliability of the BES. o Stated or assigned values should be sufficient for modeling purposes for units having nameplate ratings < 75 MVA. If the BA or TOP needs validated data on a smaller unit or group of units then these requirements can be made known to the GOP per TOP-002-2 R13.
Response: Thank you for your comments. The intent was to use the same thresholds as included in the compliance registration criteria. 20 MVA is the registry criteria.		
American Electric Power	Yes	
Bauer	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	

Dynegy Inc	Yes	
E.ON U.S.	Yes	
Electric Market Policy	Yes	
GO/GOP	Yes	
Luminant	Yes	
NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	
Progress Energy	Yes	
South Carolina Electric and Gas	Yes	
Xcel Energy	Yes	
Manitoba Hydro	Yes	Agree to include units connected to 100 KV and above.
Response: Thank you for your comment. The SDT agrees.		
ITC Holdings	Yes	Comments: The 100 kV reporting for this requirement is consistent with other NERC reporting requirements.
Response: Thank you for your comment. The SDT agrees.		
Indiana Municipal Power Agency	Yes	IMPA agrees that the standard should be consistent with the current Compliance Registry and supports how units are verified in the standard.
Response: Thank you for your comment. The SDT agrees.		
Puget Sound Energy	Yes	Puget Sound Energy agrees with being consistent with the Compliance Registry. It seems that the compliance registry criteria would determine whether an entity has to comply with any of the NERC standards including this one and then the current BES definition would establish what facilities are applicable. The need

		to describe the Faclities under section 4.2 is not clear. We assume that any approved regional definition of the BES would dictate applicability ultimately. Regarding the verification requiremetns as proposed, it is unclear why annual verification (for most units) is necessary as much of the data will not change over an annual timeframe and most change that may occur would likely not cause a reliablity impact as it relates to the study work the Planning Coordinator or Resource Planner uses this information for. We would request that the testing be done on a 5 year cycle which follows other practices for providing data (i.e., WECC has been using a 5 year cycle for testing since 1997, and the results have proven to be entirely adequate).
Response: Thank you for your comments. The SDT agrees. The SDT also agrees with the suggested periodicity included this in the revised standard.		
SERC Generation Subcommittee (GS)	Yes	Stated or assigned values should be sufficient for modeling purposes for units having nameplate ratings < 75 MVA. This should apply to many regions. If the BA or TOP needs validated data on a smaller unit or group of units then these requirements can be made known to the GOP per TOP-002-2 R13.
Response: Thank you for your comments. TOP-002, R13 is proposed for retirement.		
Northeast Power Coordinating Council	Yes	The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
Response: Thank you for your comments. Tariffs, Market Rules, and Interconnection agreements are independent of the reliability obligations being addressed by this standard. Regarding reliability, the SDT acknowledges that if the correct system operations circumstance exists then the data obtained by performing the Real Power capability verification required by the MOD-024 standard (now incorporated into the MOD-025 standard) for system planning purposes may yield the same results as could be obtained by using equipment nameplate ratings, unit operational data, EMS data, forecast information, etc. required to be provided to the ERO by other standards. Recognize this alternate set of data is collected for other reliability purposes and is not guaranteed to represent actual capability. As such, there is a reliability need to specifically require Real Power capability verification. The SDT also acknowledges it is acceptable to utilize reasonable assumptions when performing long term planning analysis however the SDT also believes it is prudent from a reliability concern to incorporate established unit operational constraints into the planning model when relevant. Units may be derated or constrained for a variety of legitimate long term reasons. Likewise, units derated or constrained today may have restrictions released in the future. Only by performing a Real Power capability verification to determine what the unit is capable of supplying can accuracy of needed reliability data be assured. **Also, please see the summary response to Question 1.**		
American Transmission Company	Yes	The generating unit qualifications are consistent with the presently Compliance Registry criteria.

Response: Thank you for your comment. The SDT agrees.		
Florida Municipal Power Agency and Some Members	Yes	There is no need to expand the scope of the standard beyond the registration criteria. As the SDT has pointed out, only about 4% of the power system capacity is connected below 100 kV. Most of these generators are modeled, and many are already tested beyond the scope of the standard. So, causing regulation of generator verification to these generators may only improve accuracy for a small portion of the 4%. Such gain in accuracy at < 100 kV is easily overwhelmed by the inaccuracy of load forecasts, and by the variation of generator output with ambient conditions (e.g., temperature, humidity, barometric pressure, etc.) outside of forecasted ambient conditions. So, such effort is wasted because any supposed gain in accuracy by going below 100 kV is illusory and lost as compared to other forecast inaccuracies outside the control of anyone (e.g., the weather).If anything, the level of verification required in the standards could be reduced for smaller units (e.g., less frequent), even more so than as described in the standard. However, this would create a complex “tiered” standard difficult to understand and monitor. Hence, we congratulate the SDT on developing a balanced perspective that truly focuses on what is important to maintain the reliability of the BES.
Response: Thank you for your comments. The SDT agrees.		
Cowlitz County PUD	Yes	This approach makes it easy for the owner to know when compliance is necessary. However, 20 MVA redline across the board for any single unit seems too low. Any significant generation will be connected at 100 kV or greater, but not all generation is significant just because it is connected at a certain voltage. A simple redline is easy to manage, but is new small generation development being discouraged with this low bar? I am not dead set against this applicable level, but I think some research into discovering the unintended consequences should be made.
Response: Thank you for your comments. The SDT defaulted to using the same thresholds as used for compliance registration.		
Independent Electricity System Operator	Yes	This is a simple approach that should be supported. Notwithstanding our response and consistent with our reply to Q1, where the provision of this information is already required in other standards, those requirements should not be duplicated here.
Response: Thank you for your comment. Agree. Please see the summary response to Question 1.		
Calpine Corporation	Yes	We agree with the demarcation but recommend it be reworded to exclude generation units interconnected at voltages below 100 kV and units below 20 MVA to avoid unnecessary discussion of registration criteria.
Response: Thank you for your comment. The SDT defaulted to using the same thresholds and wording as used for compliance registration. Identifying a list of units that would be excluded does not seem necessary.		

FirstEnergy	Yes	We agree with the proposed thresholds because they are consistent with the NERC compliance registry.
Response: Thank you for your comment. The SDT agrees.		

3. After much discussion the SDT decided to require the verification be performed over a period of at least "one continuous hour" regardless of the type of unit because most units have reached steady state operation within one hour. Do you agree with this approach? If not, please explain.

Summary Consideration: The majority of respondents felt that one hour would meet reliability requirements. A few respondents felt that it was too long while others felt that the Planner should be allowed to request a longer period. There was concern expressed over hydro unit capability varying with reservoir levels. The SDT felt that these variations fall outside the intent of the verifications envisioned for this standard.

Organization	Yes or No	Question 3 Comment
Generators Supporting Elimination of MOD-024		NA. This standard is not needed for reliability.
Response: Thank you for your comment. Please see the summary response to Question1.		
PacifiCorp	No	: Sufficient detail on the data requirements during the one hour sampling period required under the proposed standard has not been provided. Please provide some direction on the required sampling rate and acceptable methods for data collection. It is unreasonable to require that a maximum boiler capacity test be performed twice a year to validate the unit real power capability. Biannual capture of historical data would be the preferred method of unit capability validation. Water resource impacts on hydroelectric facility capability have not been addressed sufficiently by the proposed standard. Please provide clarification on expectations for data collection at hydro facilities when water resources do not support operation at unit capability.
Response: Thank you for your comments. Sampling rate; unit output is integrated over an hour. **On the unreasonableness concern; The standard allows for the temperature adjustment of the summer verification to satisfy the winter requirement. The SDT agrees that unit performance during verification is not a guarantee of future performance. The standard allows the GO to use operating data. The planning coordinator has the ability to review past unit performance to insure that the verification value submitted is reasonable, indicative of past unit performance. There is nothing in the standard to prevent the planning coordinator from questioning the submitted data. Variable energy units shall report the Real Power obtained that was achieved during the time of the Reactive Power verification. Note that the revised standard requires most verifications only once every five years.**		
IRC Standards Review	No	A Planning Coordinator should be afforded the right to request periods other than one continuous hour as needed for ad hoc evaluations e.g. for Ancillary Service evaluations over a 15 minute period or for special

Organization	Yes or No	Question 3 Comment
Committee		case studies e.g. fuel disruption analysis. The default period may be agreed to as one continuous hour but that should not be the mandated period.
Pepco Holdings, Inc	No	A Planning Coordinator should be afforded the right to request periods other than one continuous hour as needed for ad hoc evaluations e.g. for Ancillary Service evaluations over a 15 minute period or for special case studies e.g. fuel disruption analysis. The default period may be agreed to as one continuous hour but that should not be the mandated period.
Response: Thank you for your comments. If a planning coordinator is performing the ad hoc evaluation for an ISO or RTO then the rules of the ISO or RTO can be structured to meet the intended needs. The SDT agreed that one hour met the needs of modeling data. The standard was drafted to meet reliability needs and not market requirements. Market rules and reliability requirements may be different.		
ERCOT ISO	No	ERCOT ISO disagrees with this aspect of the proposal. The methodology for verification should be left to the relevant NERC functional entities. As noted by the SDT, the Transmission Planner needs to communicate the conditions under which the resource is required to verify its real-power capability. This discretion afforded the TP should apply to all aspects of the verification, including the time period the unit must run. At a minimum, the proposed one-hour time period should be a default and the requirement should provide for alternative time periods to accommodate regional differences and different testing purposes - e.g. for ancillary services.
Response: Thank you for your comments. If ERCOT feels that there is a significant regional difference that requires an enhanced standard for the ERCOT Region then ERCOT ISO should submit a SAR to TRE to develop such a Regional standard. But again the ERCOT ISO is the market that may need different data points and as the market has the right to craft the rules needed to get those data points. The planners on the SDT felt that one hour was a sufficient period for the verification to gather the real power data needed for modeling.		
Luminant	No	Luminant would prefer 30 minutes at full load, as this approach has been utilized effectively in ERCOT for several years.
Response: Thank you for your comment. The planners on the SDT felt that one hour was needed to establish a units' real power capability for modeling, and most stakeholders who responded to this question supported the one hour period.		
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
Response: Thank you for your comment. Please see the summary response to Question 1.		

Organization	Yes or No	Question 3 Comment
Duke Energy	No	Need to reword Attachment 1, section 2.1 to add clarity. Suggested rewording: For nuclear and fossil units, record data for at least one continuous hour of normal operation during the winter period. More time may be required or used to achieve stable conditions.
Response: Thank you for your comment. The standard only requires one continuous hour of data. The standard allows for the GO to conduct the verification over any hour they select.		
E.ON U.S.	No	One hour is too short. This period could allow a company to provide more of an "optimum" or "maximum" capability, rather than an average capability (e.g., during one hour soot blowers might not have to be run, etc.). The current 4-hour average test is more reasonable/reliable. Attachment 1 should be revised to specify a verification period of "at least 1 hour." The use of the term "normal operation" in Attachment 1 is not specific enough and is open to interpretation. Since generating capacity has market value, Gen Owners may desire to maximize the verified/reported capability of their units - even if such performance can only be attained for a single hour. This would not be consistent with the notion of dependable or continuous capacity which should be the basis used for reliability planning purposes.
Response: Thank you for your comments. The idea behind the standard is for the planners to get a real power value of what the unit is capable of producing 24/7. The SDT discussed the verification time period at length and concluded, based on its collective knowledge and experience, proposed that one hour was sufficient for modeling purposes, and most stakeholders who responded to this question agreed with this duration. The planner always has the ability to check the number submitted under the standard against actual unit performance to gauge validity. Normal operation is what a unit is called on to produce during normal conditions. The SDT believes that the GO understands what normal means. It does not mean taking actions such as taking heaters out of service to get maximum output that is allowed in some ISOs that have capacity markets. In fact it is in the best interest of the GO to submit a value that it is sure the unit is capable of producing 24/7. The SDT does not believe that four hour verification is any more accurate or reflective of unit capability than one hour verification. Again this verification does not establish market value it establishes the unit's capability for system modeling for reliability studies.		
Arizona Public Service Co.	No	Our experience is that 30 minutes are adequate to reach steady state conditions. There are no benefits to be derived by going beyond 30 minutes.
Response: Thank you for your comment. The planners on the SDT, based on their collective knowledge and experience, proposed that one hour was needed to establish a unit's real power capability for modeling. Most stakeholders who responded to this question supported the one hour period.		
Exelon Generation Co LLC	No	Short duration testing conducted when conditions are the most favorable do not provide an accurate indication of unit preformance under all conditions.
Response: Thank you for your comment. The standard's goal is to capture the unit's performance under normal operating conditions. The intent of		

Organization	Yes or No	Question 3 Comment
the standard is to capture what the unit can do 24/7 without taking measures that would temporarily increase the unit's output. The planner can always review the TOP's EMS data to check the real power number.		
Bauer	No	The intent of the requirement of the previous version was to provide realistic summer and winter generator capability. For hydro units, the process detailed in this version only provides a vague assessment of normal and most likely not be the realistic capability of the generator. The process requires the units to be operated "normally" which is undefined and to adjust the MW to reflect forecasted (summer or winter) reservoir conditions. Hydro units may be "normally" operated throughout their operating range. Without specific guidance that the operation should utilize a normal "full load" condition, the true summer capability may not be known. Specifically, if a generator , at some time other than summer is, operated at 50% gate during the operational snap shot produces xx MW, then the xx MW at 50% gate will be indexed for the summer reservoir level. The true capability of the generator at 100% gate (normal full load) during summer would actually be much higher. The language would need to ensure that the full load would reflect limitations other than those introduced by head.
Response: Thank you for your comments. The standard references maximum nameplate rating as a reference point for performing the verification. Variable energy units do present a challenge. The SDT understands operational and regulatory constraints may exist; run variable units at what capability can be provided. Constraints are implicitly recognized within the standard process. Refer to Attachment 1, section 2.1 language. The combined MOD-024 and 025 require the GO to report the real power capability at the time of the Reactive Power verification. **The planning coordinator has the ability to review past unit performance to insure that the verification value submitted is reasonable, and indicative of past unit performance. There is nothing in the standard to prevent the planning coordinator from questioning the submitted data. The scope of this standard is focused on verifying the data used in planning models –not in providing updates to capabilities for use in near real-time operations.**		
AMEA	No	The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
Response: Thank you for your comment. The GV SDT has utilized the NERC Registration Criteria and believes that it is appropriate for this continent wide standard. Individual Regions are free to make adjustments if they are deemed necessary, by submitting a request for a variance		
The Empire District Electric Company	No	The nameplate reating should be sufficient for determining output. In this day of being environmentally friendly, why would we as a country want to subject each generator to these types of tests using precious fuel and expelling pollutants when nameplate ratings have been sufficient for years?
Response: Thank you for your comment. The SDT does not agree that nameplate ratings are sufficient to ensure reliability. The SDT acknowledges that if the correct system operations circumstance exists then the data obtained by performing the Real Power capability verification required by the		

Organization	Yes or No	Question 3 Comment
MOD-024 standard (now incorporated into the MOD-025 standard) for system planning purposes may yield the same results as could be obtained by using equipment nameplate ratings, unit operational data, EMS data, forecast information, etc. required to be provided to the ERO by other standards. Recognize this alternate set of data is collected for other reliability purposes and is not guaranteed to represent actual capability. As such, there is a reliability need to specifically require Real Power capability verification. The SDT also acknowledges it is acceptable to utilize reasonable assumptions when performing long term planning analysis however the SDT also believes it is prudent from a reliability concern to incorporate established unit operational constraints into the planning model when relevant. Units may be derated or constrained for a variety of legitimate long term reasons. Likewise, units derated or constrained today may have restrictions released in the future. Only by performing a Real Power capability verification to determine what the unit is capable of supplying can accuracy of needed reliability data be assured. Verification should be performed. The standard does not require units to run for verification only. The SDT agrees in general with comments raised regarding environmental stewardship concerns and believes this consideration is rendered moot by requiring verification once every five years. It is reasonable to assume that the unit will run for at least one hour at maximum capability during the five year period. Please see the revised standard.		
Consolidated Edison Co. of New York	No	The SDT should change the verbiage to “a minimum of one continuous hour of normal operation” to avoid confusion that the unit can be ramping up to full load during the test.
Response: Thank you for your comment. Ramping is not performed during verification. The SDT envisions Generator Owners will first realize steady state conditions at maximum capability before commencing the one hour capability test.		
Progress Energy	No	We agree with the approach as stated in Question 3 but have selected NO here because the proposed standard itself does not reflect the approach stated. For Attachment 1, Sections 1.1, 1.2, 2.1, and 2.2, these should be changed to say “for at least one continuous hour...”
Response: Thank you for your comment. So noted the SDT has made the suggested change.		
SERC Generation Subcommittee (GS)	No	We agree with the approach as stated in the questions but have selected NO here because the standard does not reflect the approach stated. For Attachment 1, Sections 1.1, 1.2, 2.1, and 2.2, these should be changed to say “for at least one continuous hour...” to assure stable conditions.
Response: Thank you for your comment. So noted the SDT has made the suggested change.		
FirstEnergy	No	We do not agree that one hour is sufficient for Fossil and Nuclear units (per Attachment 1 Sec. 1.1 and 2.1). The SDT should consider at least 4 hours or, at a minimum, require that the unit demonstrates it has reached equilibrium.
Response: Thank you for your comment. The idea behind the standard is for the planners to get a real power value of what the unit is capable of producing 24/7. The SDT, using its collective knowledge and experience, discussed the verification time period at length and proposed that one hour		

Organization	Yes or No	Question 3 Comment
was sufficient for modeling purposes. Most stakeholders who responded to this comments agreed with the one hour. The planner always has the ability to check the number submitted under the standard against actual unit performance to gauge validity. The SDT does not believe that four hour verification is any more accurate or reflective of unit capability than one hour verification.		
GO/GOP	No	We feel that one hour is too short. We recommend verification be performed one hour after the unit has reached steady state operation since some units may take different lengths of time to reach steady state.
Response: Thank you for your comment. The idea behind the standard is for the planners to get a real power value of what the unit is capable of producing 24/7. The SDT, using its collective knowledge and experience, discussed the verification time period at length and proposed that one hour was sufficient for modeling purposes. Most stakeholders who responded to this comments agreed with the one hour. The planner always has the ability to check the number submitted under this standard against actual unit performance to gauge validity. The SDT does not believe that four hour verification is any more accurate or reflective of unit capability than one hour verification. Ramping is not performed during verification. The SDT envisions Generator Owners will first realize steady state conditions at maximum capability before commencing the one hour capability test.		
American Electric Power	Yes	
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Calpine Corporation	Yes	
Consumers Energy	Yes	
Cowlitz County PUD	Yes	
Dynegy Inc	Yes	
Electric Market Policy	Yes	
Florida Municipal Power Agency and Some Members	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 3 Comment
Operator		
Long island power Authority	Yes	
NERC Standards Review Subcommittee	Yes	
North Carolina Electric Membership Corporation	Yes	
Oglethorpe Power Corporation	Yes	
Puget Sound Energy	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission/Generation	Yes	
Indiana Municipal Power Agency	Yes	IMPA agrees with the one hour testing and the reasoning that the SDT used to decide on this time period.
Response: The SDT agrees, and thank you for your comment.		
ITC Holdings	Yes	None
Manitoba Hydro	Yes	One hour testing is sufficient, and does not expose the unit to unnecessary stress or take excessive time to complete.
Response: The SDT agrees and thank you for your comment.		
Hydro-Québec TransEnergie (HQT)	Yes	See answer to Q1.

Organization	Yes or No	Question 3 Comment
Response: The SDT agrees, and thank you for your comment.		
Northeast Power Coordinating Council	Yes	The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this data is incorporated in existing standards projects.
Response: Thank you for your comments. Please see the summary consideration of comments on Question 1.		
Xcel Energy	Yes	While we agree that one hour of data is adequate to verify the capability, in our experience it takes at least 30 minutes for a steam turbine unit to stabilize if it has been operating at a lower load. We believe the criteria should take into consideration of an applicable "stabilization period" prior to data collection.
Response: Thank you for your comment. Ramping is not performed during verification. The SDT envisions Generator Owners will first realize steady state conditions at maximum capability before commencing the one hour capability test.		

4. **The SDT felt that units that cannot sustain continuous operation, oftentimes known as intermittent, variable or limited energy units, such as a Wind Generating Station or run-of-river hydro, etc., should be exempt from this standard because such units are typically represented in studies with "on average" or "discounted" values. Do you agree with this approach? If not, please explain.**

Summary Consideration: While most stakeholders who responded to this question supported the original proposal, several commenters disagreed with the exemptions for intermittent, variable and limited energy units, and indicated that these units do impact reliability and should be included in the standard if they meet the default thresholds identified in the compliance registration criteria. The SDT revised the standard to require testing of all generating units greater than 20 MVA and all generating plants/facilities containing greater than 75 MVA (gross aggregate name plate rating), directly connected to the bulk power system at 100 kV or above. The standard applies to all generation technologies.

Organization	Yes or No	Question 4 Comment
Generators Supporting Elimination of MOD-024		NA. This standard is not needed for reliability.
Response: Thank you for your comment. Please see the summary consideration of comments on Question 1.		
American Electric Power	No	AEP believes that it is important to have intermittent, variable, and limited energy units to be in compliance with this standard. Technical assumptions made for studies are important, but it is important to ensure that the stated capabilities for such units are verified.
Response: Thank you for your comment. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies.		
Consolidated Edison Co. of New York	No	All units meeting the voltage level and output level as specified in Section 4.2 should be tested. From both an operating horizon and planning horizon, it is important to have an accurate model of the system.
Response: Thank you for your comment. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies.		
CenterPoint Energy	No	CenterPoint Energy disagrees with exempting certain types of generation resources from Requirement 1 and Requirement 3; therefore, CenterPoint Energy recommends deleting 4.2.3 "Variable energy units such as

Organization	Yes or No	Question 4 Comment
		wind generators, solar, and run of river hydro are exempt from the requirements of this Standard." CenterPoint Energy agrees that oftentimes such generation resources are represented with "on average" or "discounted" values. However, all planning models do not use "on average" or "discounted" values as there are needs to study expected generation patterns. For example, wind generation typically peaks in the early morning hours in west Texas and should be modeled at a lower output in planning models which represent the peak load hour which occurs in the summer, typically around 5 PM. Transmission planners would need to ensure that there is adequate transmission when west Texas wind is operating at its peak output in the early morning hours. For this purpose, there is a need for a planning model with all wind generation operating at peak output. In addition, wind generation typically reaches a peak coincident with the peak load hour in the Gulf Coast area. So, this generation would be modeled at peak output in a planning model representing the peak load hour. In both of these cases, planning models need the net real power capability of wind units verified by actual unit testing.
Response: Thank you for your comments. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies.		
ITC Holdings	No	Comments: A one hour typical rating/capability should be provided by the generators for run of river hydros.
Response: Thank you for your comment. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies		
ERCOT ISO	No	ERCOT ISO disagrees with this aspect of the proposal because the performance/capability of all resources, including variable output resources, effects system planning and operations. Accordingly, contrary to the position of the SDT, the data from variable energy resources (e.g. intermittent renewable) is also needed for reliability. Although these resources are subject to the variability in terms of their fuel source (e.g. wind), there are methods of estimating the capacity and energy from these resources. These estimates provide value for the purposes of this standard. Variable energy resources should not be exempt from this requirement. The Standard should include these resources, provided that they are subject to rules that reflect the variability of their production. The verification methodologies established by the respective NERC functional entities can accommodate variable resources in a manner that is consistent with the practices within their respective regions.
Response: Thank you for your comments. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies.		
Calpine Corporation	No	If there's truly a reliability need for verification of capability, this segment of generation needs to be addressed.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies.		
Indiana Municipal Power Agency	No	If these units cannot sustain continuous operation, then they can report/record the highest hour or an average output for the hour.
Response: Thank you for your comment. The SDT understands operational and regulatory constraints may exist; run variable units at what capability can be provided. Constraints are implicitly recognized within the standard process. Refer to Attachment 1, section 2.1 language.		
Bauer	No	It is not appropriate to consider the variability of wind generating stations comparable to the operation of a run of the river hydro. Run of the river hydro tends to be less variable and pose a lower regulation burden on the BES than wind generation. We justify this position in that the operator can estimate the energy produced during a month and even schedule the capacity at which the generator is operated, whereas wind cannot. As such an operator is able to provide a verification of the capability of our run of the river plants.
Response: Thank you for your comments. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies.		
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
Response: Thank you for your comment. Based on the views of the SDT and the preponderance of industry comments the SDT is recommending retaining the requirement to verify generator real power capability.		
North Carolina Electric Membership Corporation	No	Peaking units that have a limited cumulative energy per year (i.e. low capacity factor below 5%) should be provided the same treatment. The SDT should consider providing the PC with the flexibility for designing tests “needed” for verification such that all units are either handled in the same way.
Response: Thank you for your comment. The SDT has modified the standard to require verification of the real power capability for all generator technologies.		
Pepco Holdings, Inc	No	Providing the Planning Coordinator with the flexibility for designing tests “needed” for verification provides the opportunity to handle all units the same way (i.e. how the PC asked).
Response: Thank you for your comment. The SDT decided to revise the standard and require the Generator Owner to provide the data to the Planning Coordinator – it is then the Planning Coordinator’s responsibility to share the data with other planning entities. The Planning Coordinator has the		

Organization	Yes or No	Question 4 Comment
ability to review past unit performance to insure that the verification value submitted is reasonable, indicative of past unit performance. There is nothing in the standard to prevent the Planning Coordinator from questioning the submitted data.		
FirstEnergy	No	We believe that capabilities of intermittent units such as wind and solar can be adequately verified by testing, tracking of operational data, or calculations if testing or operational data is not possible or incomplete. Furthermore, it has been forecasted that utilization of these types of units will expand and most states will have Renewable Energy requirements of 20-25% of generation in the future. This would represent a large percentage of generating unit Real Power Capability not being verified. Excluding these units from verifying their capability will not improve reliability but will reduce it. The goal of this standard is to determine the capabilities of all generating units. The Generator Owner of intermittent units should provide their maximum capability through verification, test or calculation along with capacity factor data. This information could then be used by the Transmission Planner to plan for a reliable system based on the Transmission Planner's engineering judgment and considering other factors as the units Interconnection Agreement contractual arrangements (i.e. energy only unity, participates in a capacity market, etc.) Therefore, we suggest that this SDT incorporate requirements to verify intermittent, variable, and limited energy units. We also suggest the SDT should consider language similar to RFC standard MOD-024-RFC-01 Requirement R2.2.3 to accomplish verification of intermittent, variable, and limited energy unit capabilities.
Response: Thank you for your comments. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies.		
Southern Company Transmission/Generation	No	We recommend all hydro units be excluded since capability is dependent on available water levels. GOP's with appreciable hydro capacity have established procedures or processes to predict the capability of these units.
Response: Thank you for your comment. Based on the views of the SDT and the preponderance of industry comments the SDT is recommending retaining the requirement to verify generator real power capability		
SERC Generation Subcommittee (GS)	No	While intermittent resources may not make up a significant portion of supply in most regions at this time, future development may result in significant portions of supply being made up of these resources, and relying only on design or nameplate values, for the purposes of transmission planning, will be as inappropriate for these units as it is for existing generation.The standard should focus on determining the appropriate generator ratings to be supplied to the planning processes, not how they are ultimately used.
Response: Thank you for your comment. The SDT agrees and has modified the standard to require verification of the real power capability for all		

Organization	Yes or No	Question 4 Comment
generator technologies.		
Progress Energy	No	While we have indicated that we disagree with the exemption, it may be more appropriate to address testing of "intermittent" resources separately due to their different use in planning and operational studies. However, we think the basis for exemption by the SDT is incorrect. The SDT has confused the issue of rating with how that rating is used in planning studies. There are two fundamental questions that must be answered for each resource in any planning study: (1) what is the resource capable of producing under some standard set of conditions, and (2) how much will it produce under the conditions assumed in a planning study. Historically, these two questions are merged for resources which are dispatchable and controllable to a sustained output level. In other words, if we test a conventional fossil or nuclear generator and determine it can produce X MW under the test conditions, we assume it can produce X MW under study conditions like peak demand, off-peak or shoulder load conditions. However, we might model the unit as producing zero or something less than its capability due to economic or some other dispatch consideration. We do not try and represent some average value of its production over time.When intermittent resources are considered, we still need to know how much a unit is capable of producing at its maximum output. We would not size the interconnection for "average" output. We need to know what it might produce under ideal conditions. Taken further, we know that at some point in its operation, the intermittent resource will produce at its tested value, and it will be up to the planner to determine if that condition needs to be studied. For example, 100 MW of nameplate generation may produce 30 MW on the average over a year's time, but it might produce the full 100 MW at an off-peak hour, and that may need to be studied. How do we assure ourselves that the 100 MW of nameplate is actually capable of 100 MW?While intermittent resources may not make up a significant portion of supply in most regions at this time, future development may result in significant portions of supply being made up of these resources, and relying on design or nameplate values will be as inappropriate for these units as it is for existing generation.The standard should focus on determining the appropriate generator ratings to be supplied to the planning processes, not how they are ultimately used. As the standard itself states:3. Purpose: To ensure that planning entities have accurate generator Real Power capability modeling data used in system planning studies
Response: Thank you for your comments. The SDT fundamentally agrees with comments on how planners utilize data. The requirements being incorporated into MOD-025-1 aim to determine unit capability which will be different than nameplate rating in most cases. It is acceptable to utilize reasonable assumptions when performing long term planning analysis however the SDT also believes it is prudent from a reliability concern to incorporate established unit operational constraints into the planning model when relevant. Units may be derated or constrained for a variety of legitimate long term reasons. Likewise, units derated or constrained today may have restrictions released in the future. Only by performing a Real Power capability verification to determine what the unit is capable of supplying can accuracy of needed reliability data be assured. **The majority of industry agrees variable resources require verification. The SDT understands operational and regulatory constraints may exist; run variable units at what capability can be provided. Constraints are implicitly recognized within the standard process. Refer to Attachment 1, section 2.1 language. Capability as determined for variable resources is better representative of expectation for normal planning than rating information or**		

Organization	Yes or No	Question 4 Comment
momentary peak values recorded. The SDT has modified the standard to require verification of the real power capability for all generator technologies.		
American Transmission Company	Yes	
Arizona Public Service Co.	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Dynegy Inc	Yes	
Electric Market Policy	Yes	
Exelon Generation Co LLC	Yes	
Florida Municipal Power Agency and Some Members	Yes	
GO/GOP	Yes	
Hydro-Quebec TransEnergie (HQT)	Yes	
Long island power Authority	Yes	
Luminant	Yes	
NERC Standards Review Subcommittee	Yes	
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 4 Comment
Council		
PacifiCorp	Yes	
Puget Sound Energy	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
The Empire District Electric Company	Yes	
We Energies	Yes	
Xcel Energy	Yes	
E.ON U.S.	Yes	E.ON U.S. believes that this is reasonable at the present time but with the proposed massive build-out of wind generation this may need to be re-visited in the future.
Response: Thank you for your comment. Based on the views of the SDT and the preponderance of industry comments the SDT is recommending extending the requirement to verify generator real power capability to all technologies including variable, intermittent, and energy limited generators.		
Bonneville Power Administration	Yes	It seems like Wind and Solar should do a report for their peak generation for Summer and Winter on a periodic basis.
Response: Thank you for your comment. The SDT agrees and has modified the standard to require verification of the real power capability for all generator technologies. The revised standard does not require seasonal (summer and winter) verifications – rather the revised standard requires verifications once every five years.		
AMEA	Yes	The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The SDT decided to revise the standard and require the Generator Owner to provide the data to the Planning Coordinator – it is then the Planning Coordinator's responsibility to share the data with other planning entities. The Planning Coordinator has the ability to review past unit performance to insure that the verification value submitted is reasonable, indicative of past unit performance. There is nothing in the standard to prevent the Planning Coordinator from questioning the submitted data.		
Independent Electricity System Operator	Yes	We do not have any concern with the proposed approach. Individual Regions or markets that identify a need to verify such units to meet local requirements can establish regional specific criteria and market rules as they see appropriate.
Response: Thank you for your comment. Based on the views of the SDT and the preponderance of industry comments the SDT is recommending extending the requirement to verify generator real power capability to all technologies including variable, intermittent, and energy limited generators.		
Manitoba Hydro	Yes	Wind generation and run of the river hydro units should be exempted.
Response: Thank you for your comment. Based on the views of the SDT and the preponderance of industry comments the SDT is recommending extending the requirement to verify generator real power capability to all technologies including variable, intermittent, and energy limited generators.		
Cowlitz County PUD	Yes	Wind generation can't buttress reliability in a pinch, therefore should not be included. Agree with the run-of-river argument. However, there are other generation plants that are limited by FERC license to the maximum cubic feet per minute of water permitted to flow through the tail race. Such generation will have name plate ratings well above the allowed possible power generation considering the available prime mover. Therefore the limiting factor is not the ambient temperature, or the thermal aspects of the generation units, but the efficiency of the generation plant to convert the maximum allowed prime mover into electrical power. This efficiency will not change much, if at all, over time. Such units should also be exempt except for a single test at maximum allowed flow.
Response: Thank you for your comments. The SDT understands operational and regulatory constraints may exist; run variable units at what capability can be provided. Constraints are implicitly recognized within the standard process. Refer to Attachment 1, section 2.1 language. Capability as determined for variable resources is better representative of expectation for normal planning than rating information or momentary peak values recorded. The SDT has modified the standard to require verification of the real power capability for all generator technologies.		

5. The SDT has developed a separate periodicity approach for identical units at the same site in Number 4.4 of Attachment 1. The Generator Owner would only be required to verify 20% of these units per year. Do you agree with this approach? If not, please explain.

Summary Consideration: Most stakeholders who responded to this question indicated support for the proposal. In response to other questions, stakeholders indicated that the frequency for testing all units should be once every five years. The SDT is planning to combine the requirements of MOD-024 and MOD-025 into MOD-025. Under the combined standard, all applicable units will be verified once every five years. To avoid having many units requiring verification in any one year, the initial implementation period proposed requires 20% of an entity's units to be done each year.

Organization	Yes or No	Question 5 Comment
Generators Supporting Elimination of MOD-024		NA. This standard is not needed for reliability.
Response: Thank you for your comment. Please see the summary response to comments submitted for Question 1.		
Exelon Generation Co LLC	No	By using information already gathered through the EMS during unit operations for market reasons would elimiate the need for "testing only" runs redusing unnecessary fuel, emmissions and start up stresses on units.
Response: Thank you for your comment. Combining the MOD-024 and MOD-025 verifications will also accomplish minimizing the need for testing runs. Please see the revised standard as it allows use of operational data provided that data meets certain criteria.		
PacifiCorp	No	Current policies within the WECC require a testing interval of five years. This interval has been sufficient for stability studies to date. We suggest incorporation of a five year interval for generator real power capability validation in the proposed standard.
Response: Thank you for your comment. The GV SDT agrees, and has proposed 5 years in the combined (MOD-024 and MOD-025) standard.		
Florida Municipal Power Agency and Some Members	No	Degradation of capacity depends on more factors than design parameters, such as hours of run-time, time from last major maintenance, etc.
Response: Thank you for your comment. The SDT agrees and the new standard will require verification for all applicable units once every five years		

Organization	Yes or No	Question 5 Comment
ERCOT ISO	No	ERCOT disagrees with this aspect of the proposal. The assumption that all units of similar type at a plant are going to perform identically is not valid in all situations. Accordingly, to ensure any potential variances between similar units at the same site are accurately captured all such units should be required to provide verification annually.
Response: Thank you for your comment. Several commenters made the same observation. The GV SDT believes that since under the combined standard all applicable units are tested at some point during the 5 year cycle, this will be accounted for under the requirements.		
South Carolina Electric and Gas	No	Even though units may be identical in nature, variables such as actual in service time could lead to deratings and make two identical units unique. If the intent of the standard is to ensure unit generating capabilities are correct for studies, then shouldn't verification be made for all units?
Response: Thank you for your comment. Several commenters made the same observation. The GV SDT believes that since under the combined standard all applicable units are tested at some point during the 5 year cycle, this will be accounted for under the requirements.		
Pepco Holdings, Inc	No	Identically designed units will not necessarily perform the same.
Response: Thank you for your comment. Several commenters made the same observation. The GV SDT believes that since under the combined standard all applicable units are tested at some point during the 5 year cycle, this will be accounted for under the requirements.		
FirstEnergy	No	Item 4.4 of Attachment 1 should begin with the statement "For units that require annual verification ..." This would better clarify that the identical unit exemption is aimed at units that qualify under item 4.1 and 4.2. We agree that not all identical units should be required to be verified annually . However, the proposal should include a statement by the Generator Owner annually confirming which units that are deemed identical when providing annual verification updates for one of the identical units. Also, the wording proposed in 4.4, "approximately 20%", is ambiguous and up for interpretation in an audit. We suggest 4.4.1 be removed. We suggest replacing items 4.4.1 and 4.4.2 with the following: "The Generator Owner of identical generator units shall verify unit capability of at least one unit annually, such that all units are verified over a five year period."
Response: Thank you for your comments. Under the revised standard (which combines MOD-024 and MOD-025), all applicable units would be verified in the 5 year cycle.		
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Please see the summary consideration in response to comments on Question 1.		
The Empire District Electric Company	No	Nameplate data should be sufficient and verification is an overburdon to industry.
Response: Thank you for your comments. The SDT acknowledges that if the correct system operations circumstance exists then the data obtained by performing the Real Power capability verification required by the MOD-024 standard (now incorporated into the MOD-025 standard) for system planning purposes may yield the same results as could be obtained by using equipment nameplate ratings, unit operational data, EMS data, forecast information, etc. required to be provided to the ERO by other standards. Recognize this alternate set of data is collected for other reliability purposes and is not guaranteed to represent actual capability. As such, there is a reliability need to specifically require Real Power capability verification. The SDT also acknowledges it is acceptable to utilize reasonable assumptions when performing long term planning analysis however the SDT also believes it is prudent from a reliability concern to incorporate established unit operational constraints into the planning model when relevant. Units may be derated or constrained for a variety of legitimate long term reasons. Likewise, units derated or constrained today may have restrictions released in the future. Only by performing a Real Power capability verification to determine what the unit is capable of supplying can accuracy of needed reliability data be assured.		
Consolidated Edison Co. of New York	No	Please see response to question 4. In addition, terms such as “identical significant control systems settings” and “similar verified capabilities” are ambiguous. Section 4.4 of Attachment 1 should be removed.
Response: Thank you for your comment. The SDT agrees, and the new standard will require verification of all applicable units once every five years.		
AMEA	No	The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
Response: Thank you for your comment. Response: The GV SDT used the NERC Registration Criteria and believes that it is appropriate for this continent wide standard. Individual Regions are free to propose adjustments if they are deemed necessary, by submitting a request for a variance. **The SDT decided to revise the standard and require the Generator Owner to provide the data to the Planning Coordinator – it is then the Planning Coordinator’s responsibility to share the data with other planning entities. The Planning Coordinator has the ability to review past unit performance to insure that the verification value submitted is reasonable, indicative of past unit performance. There is nothing in the standard to prevent the Planning Coordinator from questioning the submitted data.**		
North Carolina Electric	No	The SDT should not be concerned with administrative details.

Organization	Yes or No	Question 5 Comment
Membership Corporation		
Response: Thank you for your comment. The SDT agrees, and the new standard will require verification of all applicable units.		
IRC Standards Review Committee	No	The SDT should not be concerned with administrative details. The PC should be responsible for requesting verification when verification is needed as opposed to mandating artificial (i.e. one test for all conditions) verification for the sake of artificial verification.
Response: Thank you for your comment. The SDT agrees, and the new standard will require verification of all applicable units with greater flexibility as to when the verification is conducted **The SDT decided to revise the standard and require the Generator Owner to provide the data to the Planning Coordinator – it is then the Planning Coordinator's responsibility to share the data with other planning entities. The Planning Coordinator has the ability to review past unit performance to insure that the verification value submitted is reasonable, indicative of past unit performance. There is nothing in the standard to prevent the Planning Coordinator from questioning the submitted data.**		
Xcel Energy	No	We are in agreement with the concept as long as the caveats that the major components and control systems are identical and that the verified capabilities are similar remain in the wording.
Response: Thank you for your comment. The revised standard will require verification of all applicable units once every five years.		
American Electric Power	Yes	
American Transmission Company	Yes	
Arizona Public Service Co.	Yes	
Bauer	Yes	
Bonneville Power Administration	Yes	
Calpine Corporation	Yes	
Cowlitz County PUD	Yes	

Organization	Yes or No	Question 5 Comment
Duke Energy	Yes	
Dynegy Inc	Yes	
Electric Market Policy	Yes	
GO/GOP	Yes	
Hydro-Quebec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
Indiana Municipal Power Agency	Yes	
Long island power Authority	Yes	
Luminant	Yes	
Northeast Power Coordinating Council	Yes	
Oglethorpe Power Corporation	Yes	
Progress Energy	Yes	
SERC Generation Subcommittee (GS)	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 5 Comment
Transmission/Generation		
Manitoba Hydro	Yes	Can the verification frequency of units be lowered to less than 20% for indentical units. Can it be 10% of identical uinits, as deterioration of unit real capacity is a very slow process unless a failure occurs (and failures are picked up by other standards)
Response: Thank you for your comments. The new standard will require verification for all applicable units on a five year schedule.		
Puget Sound Energy	Yes	However, we encourage this approach to test over a 5 year period for more that just identical units as discussed in our response to question 1. A 5 year cycle for testing is adequate.
Response: Thank you for your comment. The GV SDT agrees, and the combined standard's cycle is five years.		
ITC Holdings	Yes	None
NERC Standards Review Subcommittee	Yes	Please revise 4.4 of Attachment 14.4. Alternatively for multiple units installed at the same site where the units have identical designs, identical major components, identical significant control system settings and similar "tested" verified capabilities "per MOD-024": 4.4.1 Verify approximately 20 percent of all such units annually with all units being verified over a five year period. 4.4.2 Verify at least one unit each year if fewer than five units meet the criteria in 4.4.
Response: Thank you for your comments. The revised standard will require verification for all applicable units on a five year schedule.		
E.ON U.S.	Yes	The language of 4.4 isn't clear -E.ON U.S. suggests revising to "If 5 or more units are at a single site, verify....". Does "approximately 20 percent" imply rounding to the closest whole number? If 2 identical units are at the same site - no annual test is required but both units need to be verified within a 5 year interval?
Response: Thank you for your comment. The revised standard will require verification for all applicable units on a five year schedule.		

6. The SDT believes that every Resource Planner and Planning Coordinator does not necessarily perform studies involving generating unit verified capability at the same time each year nor do they necessarily need current verified information at the same time. The SDT has developed Requirement R2 that requires the Resource Planner and Planning Coordinator to provide a schedule for receiving verified information that best fits the schedule and needs for performing studies. Do you agree with this approach? If not, please explain.

Summary Consideration: The majority of respondents supported having the Resource Planner/Planning Coordinator provide a schedule. One respondent suggested a 5 year periodicity. The SDT, based on this comment and others around the need for this standard, has combined the real and reactive power verifications in the proposed draft of MOD-025. The SDT has also dropped the planning entities (both the Resource Planner and the Planning Coordinator) from the applicability of this standard since the periodicity was revised to 5 years and no longer requires the RP or PC to provide a schedule for verifications.

Organization	Yes or No	Question 6 Comment
Generators Supporting Elimination of MOD-024		NA. This standard is not needed for reliability.
Response: Thank you for your comment. Please see the summary response to the comments submitted for Question 1.		
PacifiCorp	No	: Scheduling of generator capability verification should be set by the generator owner and generator operator within the five year cycle suggested in the Item 5 comments.
Response: Thank you for your comment. The SDT aggress with PacifiCorp on a 5 year cycle. The proposed next draft on MOD-024 combines MOD-024 with MOD-025 reactive power verification. Both the real and reactive power will be scheduled and verified at the same time.		
FirstEnergy	No	It is unclear if R2 is intended to be a one-time submission of temperature adjustment information and schedule by the RP and PC or if this is something that is required each and every time the RP and PC would "seek" the data. Requirement R2 brings into question if the GO is simply holding verification data until requested to provide by an entity who "seeks" the data. Also, as written the RP and PC could provide conflicting temperature data and schedule expectations that would needlessly overburden the GO. As described in our item 4 in our Q9 response, FE suggests that R1 is ambiguous in regards to who the GO is to provide data to on an annual or every 5 year basis. FE suggests the team modify requirement R1 or Attachment 2 to clarify the intended recipients for either annual or 5-year generation verification data. In our opinion the GO should automatically provide the data to the intended recipients. Additionally, we propose the team to set a firm expectation that summer and winter verifications would be

Organization	Yes or No	Question 6 Comment
		provide to the appropriate entities within 90 days of the conclusion of the applicable summer or winter peak period. In regards to temperature adjustment, the GO should simply provide any applicable temperature adjustment data used for the data provided and respond to inquiries from data recipients as needed and upon request.If the team elects to accept FE's proposed changes it is our opinion that R2 can be removed from the standard.
Response: Thank you for your comments. The SDT removed the requirement for the planning entity to provide the Generator Owner with a temperature adjustment. The revised standard now requires the Generator Owner to record the ambient temperature and any adjustment to the temperature and provide this information to the Planning Coordinator. **The revised standard clearly states that the Generator Owner must provide the data to the Planning Coordinator and requires verification of each unit once every five years.** **The revised standard does not require separate winter and summer verifications.** **The SDT revised the standard to require that the data be submitted to the Planning Coordinator within 90 days of conducting verification.** **The SDT did remove Requirement R2 in support of your suggestion.**		
Luminant	No	Luminant believes the test results should be submitted within 30 days of completion of the annual verification. Luminant submits the following modification to Requirements R1 and R2 to address this issue. R1. Each Generator Owner shall verify the summer and winter Real Power generation capability for each of its units in accordance with MOD-024-02 Attachment 1, Verification of Sumer and Winter Generating Unit Capability,and record and submit the verification information via MOD-024-02 Attachment 2, One-line Diagram, Table and Summary for Verification Information Reporting (or similar diagram and form), to the Resoruce Planner and Planning Coordinator within 30 calendar days of the completion of the Real Power capability verification. R2. Each Resourc Planner and Planning Coordinator that seeks verified generating unit Real Power capability data shall provide each Generator Owner: - the desired temperature to which the data is to be adjusted - the calendar dates that encompass the summer period and winter period.
Response: Thank you for your comments. The SDT considered Luminant's recommendation and has modified the standard to require submission of data within 90 days of the verification. Since the data is intended for use in planning studies, the need for the data within 30 days is not clear. **Please see the revised standard – the drafting team made significant changes including the removal of Requirement R2.**		
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. Please see the summary consideration of comments on Question 1.		
Consumers Energy	No	Testing is arranged around scheduled unit outages. Unit ratings can be normalized to specific temperatures/conditions so results can be sent at any time.
Response: Thank you for your comment. The revised standard is written in such a way as to allow for the GO to conduct the verification at a time that is convenient to the GO, and requires the GO to record the ambient temperature and any adjustments to that temperature. The revised standard does not have any requirements for the planning entities.		
North Carolina Electric Membership Corporation	No	The concept that regular period-specific verification is not necessary. If the SDT is insistent on such a schedule established by the RP/PC, we would ask the SDT to consider circumstances where the same GO owns generators in multiple operating areas thus having to comply with varying requirements by multiple PCs. This would potentially result in the GO having to comply with different schedules of these multiple PCs which could be very difficult for the GO to comply with.
Response: Thank you for your comment. Agree. The revised standard is written in such a way as to allow for the GO to conduct the verification at a time that is convenient to the GO. The revised standard does not have any requirements for the planning entities.		
E.ON U.S.	No	The fundamental concept is correct; but, rather than ambient temperature, seasonal back pressure is much more appropriate to use for corrective factors. (e.g. with temperatures - is it wet bulb/dry bulb; humidity or not; how clean are the condenser/cooling tower?) All of these factors are satisfied by correcting to back-pressure conditions).
Response: Thank you for your comment. The standard does not preclude the GO from including condenser back pressure. The revised standard requires the Generator Owner to record the ambient temperature at the time of verification and to record any adjustments to the temperature.		
AMEA	No	The MOD-024-2 draft removes the regions and entities like the Planning Coordinator from the decision making ability as to which generators are material to the BES but instead provides a blanket approach that will include generators that are and are not material to the BES.
Response: Thank you for your comment. The SDT followed the compliance registration guidelines in establishing section 4.2 Facilities. **The SDT decided to revise the standard and require the Generator Owner to provide the data to the Planning Coordinator – it is then the Planning Coordinator's responsibility to share the data with other planning entities. The Planning Coordinator has the ability to review past unit performance to insure that the verification value submitted is reasonable, indicative of past unit performance. There is nothing in the standard to prevent the Planning Coordinator from questioning the submitted data.**		

Organization	Yes or No	Question 6 Comment
IRC Standards Review Committee	No	The SRC believes with the concept that regular period-specific verification is not necessary, but does not agree with the SDT's requirement. Rather the SRC would propose that R1 and R2 be replaced by the following 3 requirements: R.1. Each Planning Coordinator that requires validation of a Generator Owner's reported generator capability for use in a NERC-mandated assessment shall submit a request to the Generator Owner specifying the applicable conditions. These conditions may include such parameters as: o Gross or Net data o Time (season) required o Boundary conditions (temperature, wind if appropriate) R.2. Each Generator Owner shall verify the Real Power generating capability for each of its units in accordance with requests from their Planning Coordinator. R.3. The Planning Coordinator shall distribute the verified data to the Resource Planners that request the data, or are known by the PC to use that data. Note: CAISO does not support the proposed R3.
Response: Thank you for your comments. As a result of reviewing other responses the SDT has revised the standard to eliminate the Applicability to the PC and has required that the data be submitted to the Planning Coordinator.		
Dynegy Inc	No	The Transmission Planner also needs this generator data. These planning entities should not be required to provide the desired temperature to which the data needs to be adjusted. Generator Owners should simply adjust the actual test data using average temperature data from a location near the plant. This provision has been incorporated in the related RFC Regional Standard MOD-024-RFC-01.
Response: Thank you for your comments. Agree – all of the planning entities need the data. The SDT decided to revise the standard and require the Generator Owner to provide the data to the Planning Coordinator – it is then the Planning Coordinator's responsibility to share the data with other planning entities. **The revised standard does not require the planning entities to provide temperature adjustments to the Generator Owners – in response to suggestions from stakeholders, this requirement was removed. The revised standard requires the Generator Owner to record the ambient temperature at the time of verification and to record any adjustments made to that temperature.**		
Bauer	No	This standard is not consistent with the NERC functional model in that it requires the submission of information is not consistent with the role of the Resources Planner. The Resource Planner's role is to

Organization	Yes or No	Question 6 Comment
		develop a long term plan for resource adequacy of specific loads within a Resource Planners area. The information furnished under this requirement would be valid for less than one year. Forecast reservoir operations are notoriously inaccurate at more than 9 months. The forecast seasonal variation is relevant for TOP and BA functions. Resource Planners would interested in average seasonal variations and any physical changes to generator capability (e.g. de-rating, up-rating, etc).
Response: Thank you for your comments. The Functional Model assigns all three of the planning functional entities, including the Resource Planner, with the responsibility for collecting data from the Generator Owner. The SDT modified the standard and now requires the Generator Owner to provide the verification data just to the Planning Coordinator. The Planning Coordinator is responsible for sharing data with other planning entities. **The frequency of verification has been changed to once every five years which more closely fits the planning entities.**		
We Energies	No	To the extent there are multiple reporting requirements for generator capacity data, a standard timeframe for reporting the information should be developed in order to minimize the potential for conflicting data on the same generator from being used for similar modeling purposes. In addition, to the extent that generator capability data will be adjusted based upon ambient conditions, the requirement to verify the summer gross Real Power generating capability only during the summer period is overly restrictive. Current standards for generator testing allows the results from any period of time to be used as long as the results are adjusted based upon ambient conditions at the time of the test to the ambient conditions that would exist during the summer.
Response: Thank you for your comments. Please see the revised standard. The SDT simplified the standard's requirements by giving the Generator Owner greater latitude on 'when' to conduct its verifications. Several commenters provided sound reasons for granting the Generator Owner latitude in conducting tests or using historical data as an alternative to a test on a schedule that permits the Generator Owner to collect the data more efficiently than under the originally proposed MOD-024. The concept of having the Generator Owner conduct the verifications in accordance with various schedules set by planning entities was not carried over into the next draft of MOD-024 (now integrated into MOD-025). **The revised standard does not require seasonal (summer and winter) verifications – rather the revised standard requires verifications once every five years.**		
Exelon Generation Co LLC	No	Using real time data from EMS would allow planners to have access to dat for anytime of year and system conditions elimiating the need to schedule testing.
Response: Thank you for your comment. The SDT recognized this and debated this issue at length. The revised standard allows the use of historical data provided that data meets specific criteria.		
Independent Electricity System	No	We agree with the RPs and PCs to specify the schedule for receiving verified information to suit their needs.

Organization	Yes or No	Question 6 Comment
Operator		However, we have concerns with the applicability which relates to the purpose of the standard. a. The purpose of the existing MOD-024-1 is: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.” This implies that the data is also used for accurate modeling of the BES which the TPs, TOPs and RCs use to assess transmission system performance. The purpose of the proposed MOD-024-2 appears to have been changed somewhat: “To ensure that planning entities have accurate generator Real Power capability modeling data used in system planning studies.” This change was not mentioned in the SAR for the project (posted for comment in April 2007). We have two concerns with this change and the corresponding requirements: (i) The data is not only used for planning, it is also used for operational planning and near-term adequacy assessments (ii) If the intent of the existing standard is to continue, then the data is used for transmission reliability assessment as well. Other applicable entities need to be added. We suggest the SDT to assess the intended users of the generator’s real power capability data. Is the data used for resource adequacy assessment only, or is it also used for system model for transmission reliability/adequacy assessment? If it is the former, then RPs and PCs would be the only users. If it’s the latter, then TPs, TOPs, and RCs can be the other users.b. In the Background Information section of the comment form, the SDT indicates that it “has taken the approach that the Transmission Planner needs to communicate the conditions under which the Generator Owner is to provide verified values.” The proposed requirement does not include TPs. We wonder if the Background Information quoted the incorrect entities, or the standard is missing the TP as an applicable entity.
Response: Thank you for your comments. The SDT removed the reference to Transmission Planner from the Standard. It is the SDT’s view that the RP, and TP can obtain any data that they need from the Planning Coordinator. Each Reliability Coordinator and Transmission Operator is required to have a data specification that it issues to the entities required to submit data – and if the RC or TOP needs data from the GO, this is a mechanism for the RC or TOP to receive data from the GO. The data used by the TOP and RC for real-time monitoring must be more accurate than the data used for planning studies. There are other requirements in other standards that require the Generator Owner or Generator Operator to keep the Transmission Operator informed of generator availability, changes to output, etc. **The purpose of the standard has not changed. The SDT views steady state models as a type of planning model.**		
GO/GOP	No	We do not agree with this approach. Validation should be performed during a period which is mutually agreed upon by both the GO and TOP to take into account seasonality. For the other periods, validations should not be required.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. Please see the revised standard. The SDT simplified the standard's requirements by giving the Generator Owner greater latitude on 'when' to conduct its verifications. Several commenters provided sound reasons for granting the Generator Owner latitude in conducting tests or using historical data as an alternative to a test on a schedule that permits the Generator Owner to collect the data more efficiently than under the originally proposed MOD-024. The concept of having the Generator Owner conduct the verifications in accordance with various schedules set by planning entities was not carried over into the next draft of MOD-024 (now integrated into MOD-025).		
Puget Sound Energy	No	While R2 allows flexibility in determining when the data is submitted, the Resource Planner/Planning Coordinator may not need this information each year. If that is the case, this annual requirement imposes an unnecessary burden on Planners and Generators to provide this information more frequently than necessary.
Response: Thank you for your comment. The STD has combined MOD-024 and 025 and moved the real power test to a 5 year periodicity in support of your suggestion.		
American Electric Power	Yes	
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Calpine Corporation	Yes	
Duke Energy	Yes	
Electric Market Policy	Yes	
Florida Municipal Power Agency and Some Members	Yes	
Hydro-Quebec TransEnergie (HQT)	Yes	
Long island power Authority	Yes	
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 6 Comment
Council		
Pepco Holdings, Inc	Yes	
Progress Energy	Yes	
SERC Generation Subcommittee (GS)	Yes	
SERC Planning Standards Subcommittee	Yes	
South Carolina Electric and Gas	Yes	
The Empire District Electric Company	Yes	
Xcel Energy	Yes	
Cowlitz County PUD	Yes	As long as it does not conflict with operational constraints of the generation plant.
Response: The SDT agrees. Thank you for your comment. The revised standard gives the Generator Owner more latitude in determining when to conduct its verifications.		
ERCOT ISO	Yes	ERCOT ISO supports this aspect of the proposal. The verification methodology and timing should be left to the discretion of the relevant NERC functional entities. As noted by the SDT, the needs for different Resource Planners and Planning Coordinators may vary. The Standard should enable the relevant entities to respect those needs, including the timing of the verification tests. By simply stating these entities should provide a schedule, the proposal provides adequate flexibility to respect regional differences. To accommodate the potential need for ad hoc testing, the requirement should provide for testing pursuant to the contemplated schedules “or as requested by the RP or PC”.
Response: The SDT agrees. Thank you for your comments. The revised standard gives the Generator Owner more latitude in determining when to conduct its verifications.		

Organization	Yes or No	Question 6 Comment
Indiana Municipal Power Agency	Yes	IMPA agrees with this approach as long as it is for only receiving the verified information and not allowing these entities to specify any type of testing period or requirements outside of this standard.
Response: The SDT agrees. Thank you for your comment. The revised standard gives the Generator Owner more latitude in determining when to conduct its verifications.		
Consolidated Edison Co. of New York	Yes	In addition, different regions of the country may have summer or winter peaking periods and will schedule tests accordingly.
Response: The SDT agrees. Thank you for your comment. The revised standard gives the Generator Owner more latitude in determining when to conduct its verifications and eliminates the requirement to conduct both summer and winter verifications.		
ITC Holdings	Yes	None
NERC Standards Review Subcommittee	Yes	R2 should be redacted to include variables and not be so constrained to temperature since there might be other variables besides temperature. These variables would be specified at the Planning Coordinator and Resource Planner discretion.
Response: The SDT agrees. Thank you for your comments. The drafting team removed Requirement R2 from the revised standard (MOD-024 now merged into MOD-025).		
Manitoba Hydro	Yes	State clearly who provides a schedule to whom. Is it Planning coordinator will provide a schedule to Resource planner for verified capability information of units? We would prefer that the requirement be to complete the testing at the required frequency, and to delete the requirement for creation and submission of a plan.
Response: The SDT agrees. Thank you for your comment. The revised standard gives the Generator Owner more latitude in determining when to conduct its verifications.		
Arizona Public Service Co.	Yes	The need for verification should also be left on the Planning Coordinator.
Response: The SDT agrees. Thank you for your comment. The revised standard requires verification of all applicable units once every five years.		
Southern Company Transmission/Generation	Yes	We agree with this requirement.

Organization	Yes or No	Question 6 Comment
Response: The SDT agrees. Thank you for your comment.		

7. Are you aware of any regional variances that would be required for this standard?

Summary Consideration: An overwhelming majority of responders believe there are no regional variances that would be required for this standard. A few responders suggested that winter validation would not be necessary or that the annual testing requirement was too frequent. The SDT addressed both in the revisions to MOD-024. The language specifying both summer and winter validations was not included in the revised standard and the testing periodicity was changed to once every five years. MOD-024 was combined with MOD-025.

Organization	Yes or No	Question 7 Comment
American Transmission Company	No	
Arizona Public Service Co.	No	
Bonneville Power Administration	No	
Calpine Corporation	No	
Consolidated Edison Co. of New York	No	
Consumers Energy	No	
Cowlitz County PUD	No	
Duke Energy	No	
Dynegy Inc	No	
Exelon Generation Co LLC	No	
Florida Municipal Power Agency and Some Members	No	

Organization	Yes or No	Question 7 Comment
Generators Supporting Elimination of MOD-024	No	
Hydro-Quebec TransEnergie (HQT)	No	
Independent Electricity System Operator	No	
Indiana Municipal Power Agency	No	
IRC Standards Review Committee	No	
Long island power Authority	No	
Luminant	No	
North Carolina Electric Membership Corporation	No	
Northeast Power Coordinating Council	No	
Northeast Utilities	No	
PacifiCorp	No	
Pepco Holdings, Inc	No	
Progress Energy	No	
SERC Planning Standards Subcommittee	No	

Organization	Yes or No	Question 7 Comment
South Carolina Electric and Gas	No	
The Empire District Electric Company	No	
ERCOT ISO	No	As discussed above, ERCOT ISO believes that there may be regional differences in the planning and operational studies where this information provides value. However, if the Standard is drafted to prescribe the reliability “end” result or obligation, and it provides for adequate flexibility with respect to how the means implemented by the relevant entities to comply with the obligation, there should not be a need for regional differences. Revising the Standard in accordance with this general principle and the specific comments provided herein should affect this result and obviate, or at least mitigate to a great extent, the need for regional variances.
Response: Thank you for your comments. The SDT believes the reliability end result and flexibility exists in the standard to allow for implementation by all regional entities. The standard is focused on providing data for planning studies, not necessarily for operational studies.		
NERC Standards Review Subcommittee	No	N/A
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
Response: Thank you for your comment. Please see the summary consideration of the comments submitted in response to Question 1.		
ITC Holdings	No	None
E.ON U.S.	No	Summer peaking regional requirements are different than winter peaking regional requirements
Response: Thank you for your comment. The SDT believes it has provided the flexibility for the MW capabilities to be adjusted to temperatures expected in each area to satisfy regional needs.		
American Electric Power	No	There are no additional variations known beyond those variations already accommodated in the draft standard.
Response: Thank you for your comment.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td>Electric Market Policy</td><td>No</td><td>We are not aware of any regional variances, but are aware that regional standards are under development.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT is aware that regional standards are under development. Some parts have been taken from those regional standards as useful and have been made part of the MOD-024-2 Draft.</td></tr>
<tr><td>GO/GOP</td><td>Yes</td><td>Different regions have different peak seasons depending on the climate.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT believes it has provided the flexibility for the MW capabilities to be adjusted to temperatures expected in each area to satisfy regional needs.</td></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td>Our preference is that RFC retire their regional standard for Real Power verification (MOD-024-RFC-01) upon completion of this continent-wide standard. However, if RFC believes their standard is still needed after this NERC standard is completed, then there may be potential regional variances required as follows:
1. The threshold for periodicity of verification for RFC is 85 MVA; NERC is proposing 75 MVA. The gap between 75 and 85 MVA would need to be addressed.
2. RFC explicitly allows for testing, including commissioning tests for new units, in lieu of operational tracking.
3. The applicability for RFC is the Generator Operator while NERC proposes applicability to the Generator Owner.
4. RFC explicitly allows for exemptions and delays in verifications when system conditions or generator issues prevent verification.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. It is expected that regional standards would be revised if necessary to account for differences between them and the NERC standard - or retired if no longer needed.
The applicability in the revised standard (MOD-024 was merged into MOD-025) uses the same thresholds as those used in the compliance registration criteria.
The SDT believes the current draft does not preclude the GO from doing either operational tracking or staged testing as long as the required data is taken.
The SDT considered both the GO and GOP and originally chose the GOP as well. The applicability was changed to GO under advisement from NERC, to align with the Functional Model.
The revised standard requires verification of applicable units once every five years – eliminating the concept of a fixed schedule for verifications.</td></tr>
</table>

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Yes	Regions with considerable hydraulic generation require verification of unit output that will be modified by calculation for rated head output for comparison. Exempting run of river plants removes this need for exemption.
Response: Thank you for your comment. After discussions with the Integration of Variable Generation Task Force, IVGTF, the SDT has modified the standard to require verification of the real power capability for all generator technologies. Consideration of modifications for rated head output will be reviewed.		
Electric Power Supply Association (EPSA)	Yes	See answer to question 9.
Response: Thank you for your comment. Please see the response to comments on Question 9.		
Xcel Energy	Yes	Some Regional Entities have developed their own requirements as directed under MOD-024-1. These would presumably take precedence over MOD-024-2. Some RTO's (e.g. MISO) have their own requirements for capability verification.
Response: Thank you for your comment. NERC's MOD-024-2, if approved or combined into MOD-025-2, may necessitate revisions to some regional standards if they are less restrictive than the NERC Standard. RTO's should review their requirements for consistency as well.		
AMEA	Yes	The current MOD-024-1 allows the regions to determine which generators must provide the requied data. Regions like SERC have developed regional supplemental standards that identifies such generators. The draft MOD-024-2 contradicts SERC's regional supplemental standards and totally removes SERC and other regions from the decision making process.
Response: Thank you for your comment. The revised standard duplicates the language of the compliance registry criteria. Regions are free to include other facilities if they see fit, by requesting a variance		
SERC Generation Subcommittee (GS)	Yes	The SERC Region is a summer peaking load region. Since unit capability (excluding hydro) is either independent of seasonal differences or will exhibit increased capacity for non summer periods, winter validation is not necessary. This would apply to summer peaking entities or regions.
Response: Thank you for your comment. The SDT has incorporated the proposed real power verification requirements into the revised MOD-025. In that revised standard, the SDT eliminated the need for seasonal verification. As envisioned, only a periodic verification would be required and other data would be calculated based on that one.		

Organization	Yes or No	Question 7 Comment
Southern Company Transmission/Generation	Yes	The SERC Region is a summer peaking load region. Since unit capability (excluding hydro) is either independent of seasonal differences or will exhibit increased capacity for non summer periods, winter validation is not necessary.
Response: Thank you for your comment. The SDT has incorporated the proposed real power verification requirements into the revised MOD-025. In that revised standard, the SDT eliminated the need for seasonal verification. As envisioned, only a periodic verification would be required and other data would be calculated based on that one.		
Puget Sound Energy	Yes	The WECC may want to continue using a 5 year cycle for testing. From the WECC experience testing annually for most units would be unnecessarily frequent.
Response: Thank you for your comment. The GVSDT agrees. In the proposed revisions to MOD-024 (now integrated into MOD-025) the real power verification frequency would be on a five year cycle, in support of your suggestion.		

8. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration: An overwhelming majority of respondents were not aware of any conflicts. A few specific conflicts were identified such as with regional standards which will have to be revised when the NERC standard is approved, a maximum hydraulic flow rate by licensing issue with some hydros and a diesel generator law in Kansas. A couple of general conflicts were suggested such as with TOP-002 and CIP standards but the drafting team could not specifically identify those conflicts.

Organization	Yes or No	Question 8 Comment
Generators Supporting Elimination of MOD-024		NA. This standard is not needed for reliability.
Response: Thank you for your comment. Please see the summary consideration of comments in response to Question 1.		
ERCOT ISO		See response to Question 7 - if the Standard provides adequate flexibility with respect to the means for complying with the reliability end prescribed by the requirements, this should mitigate any potential conflict.
Response: Thank you for your comment. The SDT believes the reliability end result and flexibility exists in the standard to allow for implementation by all regional entities.		
American Transmission Company	No	
Arizona Public Service Co.	No	
Bonneville Power Administration	No	
Calpine Corporation	No	
Consolidated Edison Co. of New York	No	
Consumers Energy	No	

Organization	Yes or No	Question 8 Comment
Duke Energy	No	
Dynegy Inc	No	
Electric Market Policy	No	
Exelon Generation Co LLC	No	
FirstEnergy	No	
Florida Municipal Power Agency and Some Members	No	
GO/GOP	No	
Hydro-Quebec TransEnergie (HQT)	No	
Independent Electricity System Operator	No	
Long island power Authority	No	
Luminant	No	
North Carolina Electric Membership Corporation	No	
Progress Energy	No	
Puget Sound Energy	No	
SERC Generation Subcommittee (GS)	No	

Organization	Yes or No	Question 8 Comment
SERC Planning Standards Subcommittee	No	
South Carolina Electric and Gas	No	
Southern Company Transmission/Generation	No	
Xcel Energy	No	
Manitoba Hydro	No	MAPP was requiring unit capability tests in MRO region prior to MOD-024 NERC standard. The overlap with FAC-008 and FAC-009 should be carefully examined to avoid confusion.
Response: Thank you for your comment. FAC-008 and FAC-009 reference facility ratings while MOD-024 proposes capability verification. The SDT is constantly vigilant of potential confusion or conflicts however if there is confusion on a specific point please bring it to our attention.		
NERC Standards Review Subcommittee	No	N/A
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
Response: Thank you for your comment. Please see the summary consideration of comments submitted in response to Question 1.		
American Electric Power	No	No known conflicts.
Response: Thank you for your comment.		
ITC Holdings	No	None
Response: Thank you for your comment.		
Northeast Power Coordinating Council	No	The collection of this data is already addressed through tariffs, Market Rules, and Interconnection Agreements. The Standard should be retired. Although data can be reliability related sufficient data is collected as dictated by other standards. NERC staff should coordinate and ensure that the collection of this

Organization	Yes or No	Question 8 Comment
		data is incorporated in existing standards projects.
Response: Thank you for your comments. Tariffs, Market Rules, and Interconnection agreements are independent of the reliability obligations being addressed by this standard. Please see the summary consideration of comments submitted in response to Question 1.		
E.ON U.S.	No	This information requires some duplicate reporting. For example, the Kentucky Public Service Commission requires resource adequacy planning and reporting of the same data.
Response: Thank you for your comment. The GV SDT agrees, some coordination may be required by the GO and various organized markets to avoid conflicts.		
PacifiCorp	Yes	: Again, water resource impacts on hydroelectric facility capability have not been addressed sufficiently by the proposed standard and may result in conflict with other regulatory standards. Please provide clarification on expectations for data collection at hydro facilities when water resources do not support operation at unit capability.
Response: Thank you for your comment. The revised standard (MOD-024 is now incorporated into MOD-025) Attachment 1, 2.2 allows for a one hour test at any time during the year and for adjustments to the data for expected resource conditions.		
Pepco Holdings, Inc	Yes	As noted in Question 1, this data is already being collected under other standards and in various organized markets. Coordination will be required to avoid conflicts
Response: Thank you for your comment. The GV SDT agrees, some coordination may be required by the GO and various organized markets to avoid conflicts. The SDT reviewed the requirements identified by stakeholders as potentially redundant with the proposed standard, and found no conflicts.		
IRC Standards Review Committee	Yes	Certain Regional Entities are currently developing or have developed standards to comply with MOD-024-1 and close coordination will be necessary to ensure that no compliance conflicts are created with the approval of this updated standard.
Response: Thank you for your comment. It will be up to the Regional Entities to review their standards to be sure they are not in conflict with the NERC's standard (MOD-024 now integrated into MOD-025) when it is approved.		
The Empire District Electric Company	Yes	I am aware the state of Kansas has a current law that forbids units that start on Diesel fuel. This could cause some issues with smaller generators in the state of Kansas.
Response: Thanks for your comment. The law, as referenced, may be more restrictive but does not appear to conflict with MOD-024-2 (now integrated		

Organization	Yes or No	Question 8 Comment
into MOD-025-2) as proposed.		
Cowlitz County PUD	Yes	Maximum hydraulic flow constraints by operation license can legally prevent maximum name plate capacity verification tests.
Response: Thank you for your comment. The standard does not require maximum name plate capacity verifications.		
AMEA	Yes	Since SERC's supplemental standards have not yet been approved by FERC I consider them proposed standards. The current MOD-024-1 allows the regions to determine which generators must provide the requied data. Regions like SERC have developed regional supplemental standards that identifies such generators. The draft MOD-024-2 contradicts SERC's regional supplemental standards and totally removes SERC and other regions from the decision making process.The draft MOD-024-2 conflicts with the new CIP standards regarding the size of significant generators.
Response: Thank you for your comments. FERC did not approve the current MOD-024 Standard calling it a fill-in-the-blank standard and directed that it be re-written as a continent wide standard. Regional standards may have to be revised. Regions would still be allowed to include requirements that are not included in the NERC version. The GV SDT does not believe there is a conflict with the CIP Standards as written. If you could be more specific as to the nature of the potential conflict the SDT will review it.		
Indiana Municipal Power Agency	Yes	This standard conflicts with the RFC approved standard, MOD-024-RFC-01. The NERC draft version of MOD-024 has the Generator Owner submitting reports to the proper entities. This conflicts with the RFC standard which has the Generator Operator submitting the reports to the proper entities. IMPA believes that NERC should resolve this issue by having the RFC standard agree with the NERC MOD-024 standard and the Functional Model. The SDT may not be able to resolve this issue, but it needs to be resolved or two different entities could be in non-compliance in the RFC region if a report is not submitted.
Response: Thank you for your comments. The RFC standard does not appear to have been approved by the NERC BOT or by FERC. Regional Standards may have to be revised to be in compliance with the NERC Standard once it is approved. **Note that the SDT consulted with the Functional Model, and it is the Generator Owner that is responsible for providing data on its units.**		
Bauer	Yes	This standard conflicts with TOP-002
Response: Thank you for your comment. The GV SDT does not believe there is a conflict with TOP-002. Please see the summary consideration of comments submitted in response to Question 1.		

9. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please provide a reference to the section, requirement or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal.

Summary Consideration: Many of the respondents made numerous suggestions for edits or changes that would provide clarity to the standard. The SDT has reviewed all comments, provided explanations and made the following edits to the revised standard (MOD-024 was merged into MOD-025):

- Edited Requirement and attachment language.
- The Generator Owner record the ambient temperature at the time of the verification and documents any adjustment to that temperature.
- The Generator Owner submits verified data within 90 days to the Planning Coordinator.
- The standard does not reference seasonal requirements.
- The revised standard does not require staged tests, and only requires verification once every five years.
- Flexibility has been given to modify the attachment-2 diagram (refer to MOD-025-1).
- Requirement R2 was not carried forward into the revised standard.
- The threshold was modified, and now includes two aspects – first the change must be expected to last at least six months, and second the change must be at least 10% of the last verified capability.
- Lower VRF defined for each Requirement.
- 5 Year verification cycle specified.
- Modified the applicability section of the standard to more closely align with the criteria in the compliance registry.

Organization	Yes or No	Question 9 Comment
Generators Supporting Elimination of MOD-024		NA. This standard is not needed for reliability.
Response: Thank you for your comment. Please see the summary consideration of comments submitted in response to Question 1.		
American Electric Power	No	

Organization	Yes or No	Question 9 Comment
Exelon Generation Co LLC	No	
Hydro-Quebec TransEnergie (HQT)	No	
IRC Standards Review Committee	No	
Long island power Authority	No	
Northeast Power Coordinating Council	No	
Pepco Holdings, Inc	No	
Puget Sound Energy	No	
South Carolina Electric and Gas	No	
The Empire District Electric Company	No	
Public Service Electric and Gas Company	No	N/A as MOD-024 should be retired as demonstrated by PSE&G response to Question 1.
Response: Thank you for your comment. Please see the summary consideration of comments submitted in response to Question 1.		
ITC Holdings	No	None
Oglethorpe Power Corporation	Yes	
PacifiCorp	Yes	: Suggest language in Section 2.2 to read “the resource planner will assess the stated winter generating capability based on a test hour of generation corrected for actual vs forecasted water elevations and flows.”
Response: Thank you for your comment. The GV SDT agrees that clarification is necessary and eliminated the identified language in the combined		

Organization	Yes or No	Question 9 Comment
MOD-024 and MOD-025 standard.		
Dynegy Inc	Yes	1. Applicability 4.1- Transmission Planner needs to be added as a Functional Entity. All Planning related entities (i.e. Planni ng Coordinator, Resource Planner and Transmission Planner) need the maximum demonstrated capability of generating units for inclusion in their planning models. 2. Requirement R2- Adjustment of generating verification data should not be dependent on a request from a planning entity. This data should be adjusted to an average temperature in all cases and recorded on Attachment 2. 3. Attachment 1, Item 3.4.5- Modify this item to correspond to recommended changes in Requirement R2 (see above comment #2). 4. Attachment 1, Item 4.5- The phrase “does not run with the periodicity described in 4.1 through 4.4” “ is ambiguous. No “periods” are included in Items 4.1 through 4.4 in Attachment 1. The intent of this provision needs to be clarified.
Response: Thank you for your comments. The SDT believes that the Planning Coordinator is the most appropriate entity to receive the data. The Planning Coordinator works cooperatively with Resource Planners and Transmission Planners. The SDT removed the need for the planning entity to provide the Generator Owner with a temperature adjustment. The revised standard has the Generator Owner record the ambient temperature at the time of the verification and documents any adjustment to that temperature. **The phrase “does not run . . .” is not used in the revised standard.**		
Electric Market Policy	Yes	1. Requirement R1 states to “submit” the Real Power generating capability: however Requirement R2 appears to suggest that the data be submitted only when requested by the Resource Planner and/or Planning Coordinator. Therefore, we suggest you remove the words “and submit” from R1. 2. Requirement R2 - the first bullet should be revised to indicate “desired condition” to which the data is to be adjusted.2. “Summer period” and “summer season” appear to be used interchangeably in Attachment 1. The same comment applies for winter.
Response: Thank you for your comments. The revised standard is clear that the Generator Owner must submit its verified data within 90 days of the date of verification to its Planning Coordinator. **The revised standard does not reference summer period or summer season - or does it reference winter periods or winter seasons.**		
Southern Company Transmission/Generation	Yes	1. The subject standard should not require annual staged full load capability demonstration for verifying MW capability. There are many factors such as system load, economic dispatch, etc that determine if a unit is

Organization	Yes or No	Question 9 Comment
		expected to be called to full load. This is especially true for the smaller (<75 MVA) units. 2. The requirement for ambient temperature monitoring during the verification period is unreasonable. The ambient temperature is not needed for unit operation, and may not be tracked, and in some cases may not be reliable. In these cases, either inaccurate data would be collected or added investment would be required. (The official ratings mentioned above are based on performance data taken at or adjusted to specified ambient conditions.) 3. Allowances for different reporting format from that in attachment 2 should be permitted. We prefer a tabular reporting method due to the number of units in our fleet. An allowance for tabular reporting of the same information as indicated in attachment 2 should be permitted. 4. In Paragraph 3 of Page 5, we recommend replacing “Number” with “Paragraph”. 5. The following comments relate to Attachment 2: a. On Page 7 we recommend the following: o moving the “Date of Report” and the associated blank line to the same line as “Unit No”. o changing “Auxiliary Transformer(s)” below point A to “Unit Auxiliary Transformer(s)” o changing “Auxiliary Transformer(s)” below point C to “Station Auxiliary Transformer(s)” o splitting the bus just below the “Point of Interconnection” and eliminating the single line diagram associated with point D. o adjusting single line diagram to fit on the page (displayed on a PC monitor) o change “MW (tertiary load, if any)”, to “MW (GSU tertiary load, if any)” at the bottom of the page b. On Page 8, we recommend the following: o delete the point D measurement line from page 8 c. On Page 9 (Summer Verification Data), we recommend the following: o Insert a blank line between the “Date of Verification...” line and the “Verification End Time...” line.- in other words, make the summer and winter verification forms identical with respect to the Date of Verification, Verification Start Time, Verification End Timed. On Page 9 & 10 (Summer and Winter Verification Data), we recommend the following: o specify if the Aux Power (MW*) column in the table is “the sum of the auxiliary loads shown

Organization	Yes or No	Question 9 Comment
		on page 7” 6. R2 is not a requirement as currently written. It is a choice that the RP or PC makes. If he seeks verfied data, then he must provide certain things to the GO. If he chooses to not seek verified data, then he is not required to do anything. This means that M2 is wrong. The RP and PC should not be required to have evidence if they chose not to seek the data. 7. R1 requires the GO to submit information but it does not indicate to whom the data should be submitted. 8. R3: The threshhold for reporting a change in MW output is too high. A change of 10 to 50 MW in a generator's output could have an impact to system stability. The threshhold should be 10 MW. 9. Paragraph 2.4 in Att 1: The first word grouping is not a sentence and reads awkwardly. It is suggested that the words "an acceptable value can be obtained" be place in front of the words "by making a temperature". 10. Paragraph 3.4.2 in Att 1: Replace the word "since" with "if" for better clarity. 11. Paragraph 3.4.4 in Att 1: Move the words "in Attachment 2" to the position just after the word "flows". This will make it clear that the sentence refers to flows in Attachments 2 rather than units in Attachment 2.

Response: Thank you for your comments.

1. **The revised standard does not require staged tests, and only requires verification once every five years.**
2. **The SDT feels that the ambient temperature could significantly affect the performance of some units, especially combustion units and should be recorded and averaged for the one hour test.**
3. **Flexibility has been given to modify the diagram which could include adding a table if all of the required data is included. The SDT modified the diagram to incorporate some of your suggestions. As a note, point D was meant for units that may have part of their aux load supplied from a different bus than the point of interconnection such as on some units that have had large emissions control retrofits. Although this load would not be subtracted from the gross/net load capability of the unit, it should relieve the confusion of where it should be grouped.**
4. **The revisions made to Attachment 1 did not include carrying forward the language proposed for modification.**
5. **The SDT agrees with several of your suggestions for clarity of Attachments 1 and 2 and adopted several of your suggestions. The SDT adopted those suggestions that seem most likely to have widespread applicability.**
6. **Requirement R2 was not carried forward into the revised standard.**
7. **Requirement R1 was modified to clarify that the Generator Owner must provide the data to the Planning Coordinator.**
8. **The threshold was modified, and now includes two aspects – first the change must be expected to last at least six months, and second the change must be at least 10% of the last verified capability.**

Organization	Yes or No	Question 9 Comment
9. Paragraph 2.4 in Att 1: The phrase proposed for revision is not included in the revised standard. **10. And Paragraph 3.4.2 in Att 1: this has been replaced with the following for improved clarity:** **a. If metering does not exist to measure specific reactive auxiliary load(s), provide an engineering estimate and associated calculations.** **11. Paragraph 3.4.4 in Att 1: The phrase proposed for clarification is not used in the revised standard.**		
Indiana Municipal Power Agency	Yes	A clarification under number five, the effective date is needed. Under effective date, both sentences need to be clarified. Is the effective date the first day of the first calendar quarter after or part of the six months after applicable regulatory approval. For example, if regulatory approved is received on June 28, 2011 and then six months after is December 28, 2011, is the standard effective on January 1, 2012 (first day of the first calendar quarter after six months) or a date in the six months (before December 28, 2011).
Response: Thank you for your comments. The SDT took the basic wording for "Effective Date", common in other standards, and applied it to this standard. The effective date is the first calendar day of the first quarter one calendar year after regulatory approvals. So, if FERC approved the standard in January of 2012, the first calendar day of the first quarter one calendar year after regulatory approvals would be April 1, 2013.		
Cowlitz County PUD	Yes	Ambient temperature correction calculation requirements may incur significant compliance costs with little return for the effort. Will the Planner be asking for operation output vs. ambient temperatures way beyond normal levels? If the required ambient temperature is beyond the operational testing ability (i.e. 500 year high), how will the engineering analysis be established and verified?
Response: Thank you for your comments. The revised standard does not include the requirement for the planning entities to give the Generator Owner a temperature adjustment – instead the Generator Owner is required to document the temperature at the time of the verification and note any adjustments made to that temperature.		
SERC Generation Subcommittee (GS)	Yes	Assuming this standard is not retired, the first bullet item under R2 should be deleted. If it is not, it should be revised as follows: o The data is to be adjusted for conditions normally experienced for summer and winter peak periods, as applicable. Industry guidance is needed on how to adjust recorded test data in Requirement R2 and Section 3.4.5 on Attachment 1. Section 3.4.5 should be expanded to allow for adjusting of data for factors other than ambient air temperature. It's unclear what is being sought by "adjusting" data to a desired temperature. For steam turbines, ambient air temperature may not impact output nearly as much as coolant temperature, when the machine is not air cooled.
Response: Thank you for your comments. As you implied, generator ratings could vary significantly with ambient temperature. Combustion turbines may also be significantly affected by ambient temperatures. Affects on other units may not be as significant so some engineering judgment and/or historical data may be required to estimate a change in capability due to changes in coolant temperature and how those coolant temperatures change		

Organization	Yes or No	Question 9 Comment
with ambient temperature. The SDT believes that the GO is the best qualified to adjust unit output for temperatures other than that at the time of the test. The objective is to give the planning entities the best estimate of Unit real power capability for the desired ambient temperatures used in planning studies. The revised standard requires the Generator Owner to document the ambient temperature at the time of the verification and to document any adjustments made to that temperature. The revised standard does not include any requirement for any planning entity to give the Generator Owner a temperature adjustment.		
Bonneville Power Administration	Yes	Attachment 2 needs modification: Attachment 2 should have a measurement point on their diagram for the gross generator output, and the table should specify what values to use in the calculation of each column (Gross capability power = new point F, Aux power = A+B+C+D, Net Power = F-A-B-C-D) Because this standard is paired with MOD-025(reactive), BPA believes they should be commented together.
Response: Thanks for your comments. The SDT agrees that some modifications were needed on Attachment 2 and has modified accordingly. After thorough consideration of all responses, the SDT is proposing to merge the requirements for MOD-024 with the requirements for MOD-025, to obtain real power verification data at the same time as reactive power verification data. To perform the reactive power verification it is necessary to go to the rated real power operating point. Therefore, recording and reporting both the real and reactive power data as part of the MOD-025 verification only makes sense. **Note that in the revised standard, the attachment does collect gross real and gross reactive generator capability.**		
Calpine Corporation	Yes	Combined cycle power plants are often built with peaking capability such as steam injection for power augmentation. The term "normal operation" should be defined and include a statement that peaking capability is included only if the unit routinely operates in this mode. Combined cycle plants are sensitive to a variety of ambient conditions in addition to temperature, such as relative humidity. The standard should be revised to include other ambient data required by the generator to adjust output.
Response: Thank you for your comments. The SDT does not believe that "normal operation" needs to be defined. **The SDT felt that ambient temperature had the most significant impact on unit capability. Adjustments made to the ambient temperature must be documented.**		
Progress Energy	Yes	COMMENT 1-The first bullet item under R2 should be revised as follows: o the desired temperature to which the data is to be adjusted for conditions normally experienced for summer and winter periods. COMMENT 2- R3 should be revised as follows:"Each Generator Owner shall report to its Resource Planner and Planning Coordinator any change that is greater than 50 MW in the gross Real Power generating capability of any unit compared with the last verification submittal that is expected to last more than six months. The Generator Owner shall make such report within 15 calendar days of the determination that the

Organization	Yes or No	Question 9 Comment
		change in capability is expected to last more than 6 months." COMMENT 3- For Attachment 1, Section 4.3, in “For each individual generating units...” change “units” to “unit”. COMMENT 4- Attachment 2, Requirement 3 provides for the RP and PC to provide the GO “the desired temperature to which the data is to be adjusted”. Attachment 2 provides a blank to record that value for adjustment in each of the Summer and Winter Verification Data sections stated as: “The recorded MW values were adjusted for the following average temperature conditions:” We suggest removing the word "average" which is inconsistent with R3. COMMENT 5- In Footnote 1, revise as follows for clarification: 1- If the winter verification is based on Summer data, provide only the date of the “summer” verification “used” not the start and end times. COMMENT 6- The standard does not address validation of initial Real Power Capability for new units.
Response: Thank you for your comments. **The SDT removed Requirement R2 from the revised standard.** **The revised standard requires the Generator Owner to report any change affecting its last verified Real Power or Reactive Power capability by more than 10% if that change is expected to last for more than six months. In the revised standard, the data is only reported to the Planning Coordinator, with the expectation that the Planning Coordinator will share that data with other planning entities.** **The typographical error does not exist in the revised standard.** **The term, ‘average’ is not used in the revised standard.** **The revised standard does not require and does not reference summer or winter verifications.** **The intent of this standard is to verify data previously provided under the MOD standards.**		
Electric Power Supply Association (EPSA)	Yes	EPSA agrees with many of the SDT’s findings in its review of current verification and data reporting practices. Entities that use generator real power capability data already receive and depend on the necessary data. The SDT’s review confirms that capability data is often already being provided due to existing requirements that should reduce the frequency for real power capability testing set forth in MOD-024. While planners have asserted the need for the data to improve modeling accuracy - the SDT review of different planning models finds that they have inconsistent needs and don’t facilitate a standard that supports reliability. EPSA respectfully requests that the SDT recognize the following objectives in crafting a standard that is responsive to FERC’s directives in Order No. 693 (see 1310): 1. MOD-24 should not preempt or duplicate the real power verification procedures that already exist in the

Organization	Yes or No	Question 9 Comment
		organized markets. 2. the frequency of real power verification in the organized market regions is driven by the annual capacity markets. System planning is a longer-term endeavor and as such real power verification for system planning purposes does not require the same annual frequency or level of precision. Thus, annual verification should not be required for any units, but rather all units should verify their real power capability on a longer cycle - i.e., the five (5) year cycle currently proposed for certain smaller and low capacity factor units. A longer verification cycle reduces the need for unnecessary fuel burn and the uniformity results in better clarity as well as ease of implementation for Generator Operators.(note below) The SDT in its review also found that enhanced communication between entities will best facilitate the exchange of generator capability data. Further, it is worth noting that the Transmission Operator (TOP), Reliability Coordinator (RC), Balancing Authority (BA) and Regional Transmission Organization (RTO) / Independent System Operator (ISO) have access to a unit's real time output through their Energy Management System (EMS). The EMS provides updated information on a real-time basis, making further testing and reporting under MOD-24 duplicative and unnecessary. In addition, the GOP is required by other reliability standards to report unit de-rates to the TOP, RC, BA or ISO immediately after they occur, again making more frequent testing and data reporting under MOD-24 unnecessary. In addition, several existing Standards require the GOP to provide data related to generating unit capability status. Note: The capacity factor limitation simply may not be implementable if a unit has a capacity factor that fluctuates from year (i.e., if a 25 MVA unit has a CF less than 5% in years 1&2, but then exceeds 5% in year 3, then it needed to be tested annually and is non-compliant).
Response: Thank you for your comments. While there is no intent to duplicate requirements that may exist within markets, some duplication may exist – the data addressed in the proposed standard is needed for reliability. **Several commenters indicated that a five-year cycle for verification should still provide reliable data for system models, and the drafting team adopted the five-year cycle in the revised standard.** **The drafting team reviewed all of the standards and requirements identified as potentially having requirements redundant with those in the proposed MOD-024 (now merged with MOD-025) and did not find any duplication.**		
ERCOT ISO	Yes	ERCOT ISO believes R1 should clearly state to whom the Generator Owner of the Attachment 1 and Attachment 2 data should be submitted.
Response: Thank you for your comment. The revised standard clearly states that the Generator Owner must provide the data to the Planning Coordinator.		

Organization	Yes or No	Question 9 Comment
FirstEnergy	Yes	FirstEnergy offers the following additional suggestions and comments: 1. We question the applicability to the Generator Owner (GO) instead of the Generator Operator (GOP). We believe the standard should apply to the GOP because the operation of the unit (operational verification and testing) impacts reliability more directly than ownership. In addition multiple ownership confuses responsibility and compliance. Only one GOP will operate a unit and perform the required verification, testing and data reporting. 2. The proposed requirements in this standard do not specifically allow for testing in lieu of operational tracking. We suggest the team add testing as an explicit alternative. 3. Several terms used in this standard should be defined to alleviate any varying interpretations; we suggest the following definitions: a. Summer/Winter Peak Period - For the summer season, the Peak Period extends from the first day of June to the last day of August. For the winter peak season, the Peak Period extends from the first day of December to the last day of February. b. Peak Period Hours - The four summer hours ending at 3 PM, 4 PM, 5 PM and 6 PM. The four winter hours ending 8 AM, 9 AM, 7 PM and 8 PM. c. Capacity Factor (expressed as a percent) - Is the net actual energy generation (MW-hours) divided by the product of the period (hours) and the net max capacity rating (MW) 4. R1 - It is not clear to whom the GO must submit this information. We suggest that the SDT add language in R1 that states the GO be required to submit verification information "as requested, in accordance with a predetermined schedule and format specified by a requesting Resource Planner, Planning Coordinator, or Transmission Planner". 5. R2 - First Bullet - The phrase "The desired temperature" is too broad; we suggest a change to "The desired ambient temperature". 6. R2 - If R2 is retained (see proposal to remove in our response to Q6), FE suggests the phrase "that seeks" be replaced with "having a reliability need for" since as written could have the unintended meaning that any RP or PC could request information of a particular generator unit owner. 7. R3 - Regarding the 50MW level, it should be clear that this would be for situations where the MW level decreased by more than 50 MW. Significant increases in MW levels could violate interconnection agreements and be used by an entity to sidestep the required studies for facility uprates 8. Att. 2 - Diagram - The transformer downstream from the GSU should be the Start-Up Transformer, not Aux Transformer as currently shown.9. In the background information provided by the SDT on pg.2 it states "... the

Organization	Yes or No	Question 9 Comment
		SDT has taken the approach that the Transmission Planner needs to communicate the conditions under which the Generator Owner is to provide verified values..". It is not clear how this standard requires the TP to communicate the conditions. Was it the SDT's intent to say the PC or RP needs to communicate the conditions as stated in R2?
Response: Thank you for your comments. 1. **After consulting with the Functional Model Working Group, the SDT was directed to make the GO responsible for reporting the data.** 2. **Although not explicitly stated, operational tracking has always been considered a permissible means of testing. This is clearer in the revised standard (now merged with MOD-025).** 3. **The following terms are not used in the revised standard:** o **Summer/Winter Peak Period** o **Peak Period Hours** o **Capacity Factor** 4. **The revised standard clearly states that the verified data must be provided to the Generator Owner's Planning Coordinator.** 5. **Requirement R2 from the initial draft of MOD-024-2 is not included in the second draft of the standard (now incorporated into MOD-025).** 6. **Requirement R2 from the initial draft of MOD-024-2 is not included in the second draft of the standard.** 7. **The 50 MW level was modified so that instead of having a MW level to trigger the reporting requirement, a change of 10% to the last verified capability that is expected to last at least six months is the trigger for reporting the change to the Planning Coordinator.** 8. **The SDT agrees that there are many different configurations in use, which is why the standard specifically allows for customization of the diagram.**		
American Transmission Company	Yes	For R1, R2, & R3, we propose a Violation Risk Factor of "Lower" and a Time Horizon of "Operations Planning, Long-Term Planning". We propose "Lower" for the VRF because more accurate real power capability values will be assured by this requirement, but reasonably accurate values are likely without this requirement. We propose "Operations Planning, Long-Term Planning" for the TH because RCs and TOPs will use this data in their operations planning studies and PCs and TPs will use this data in their transmission planning studies. For R2, replace "desired temperature to which the data" with "desired ambient coolant temperature to which the summer and winter data" for added clarity. In Attachment 1, 3.2; replace "ambient air temperature" with "ambient coolant (air, water, etc.) temperature" because the capability of different types of generators is affected by the temperature of different cooling medium. In addition, consideration may need to be given to the average pressure level of generating units

Organization	Yes or No	Question 9 Comment
		that use hydrogen for equipment cooling. Requirement 1: ATC believes that some additional clarity is needed as to those entities that will receive the information. Suggestion: "...submit to the Resource Planner and/or Planning Coordinator the information view MOD-024-2 Attachment 2..." General Comment:It should be made clear that a GO validating and reporting a change in a unit's gross Real Power capability, in particular an increase in output, to comply with this standard, does not enable or give a GO the right to inject said incremental output onto the transmission system. Any MW increase (regardless of duration or ambient conditions) must be formally considered via separate mechanisms for study and verification of the BES's ability to reliably support any such increase beyond that previously approved and included in a generation-transmission interconnection agreement.
Response: Thank you for your comments. **The SDT has proposed a "Lower" VRF for both Requirement R1 and Requirement R2 in the revised standard (now merged with MOD-025). The team did not adopt the suggestion to include both Operations Planning and Long-term Planning because the intent of the data in this standard is for use in long-range planning studies. The data is not provided to any operating entities.** **Several commenters had objections to various aspects of Requirement R2 and the drafting team has not included this requirement in the revised standard.** **The SDT feels that it is up to the GO to provide the adjusted unit capability for a specific ambient temperature and coolant pressures or temperatures. The SDT agrees that clarity was needed on who should receive the data, and the revised standard is clear that the data must be provided to the Planning Coordinator.**		
Duke Energy	Yes	Industry guidance is needed on how to adjust recorded test data in Requirement R2 and Section 3.4.5 on Attachment 1. It's unclear what is being sought by "adjusting" data to a desired temperature. Ambient air temperature may not impact output nearly as much as coolant temperature, when the machine is not air cooled. Also, Section 3.4.5 should be expanded to allow for adjusting of data for factors other than ambient air temperature (e.g. steam leaks, condenser cooling water temperature, out of service reheaters, condenser fouling, turbine blade wear....). Planners need to model to the unit's expected sustained capability. If tests are conducted under degraded plant or equipment conditions the test results need to be adjusted. Otherwise planners could plan the system for less than the full capability of the unit, which would yield a non-conservative result. Guidance is needed on how to report (i.e. actual data, adjusted data and a prognosis for sustained capability that may be achieved). The test should represent the actual condition of the equipment. If it is degraded then the unit would have less capability. However capability could be restored during a repair or outage, and demonstrated with another test.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. **Requirement R2 was not carried over into the next version of the standard. The SDT recognizes that ambient temperature affects some units more than others. The SDT also feels that it would be unreasonable to expect the Planning Coordinator to be able to convert coolant temperature to ambient temperature as that is best understood by the GO. In the revised standard the Generator Owner is required to document the ambient temperature at the time of the verification and any adjustments made to that temperature.** **The SDT agrees that accurate model data is needed and is attempting to capture the most relevant data with this standard. The SDT added a “remarks” section to the attachment so the Generator Owner can document any special conditions that should be considered when interpreting the verification data.**		
Consolidated Edison Co. of New York	Yes	MOD-024-2 requires bi-annual testing, while at the same time exempted intermittent units (e.g. wind generators) and stations with multiple units (section 4.4). A reliability standard should support reliability; therefore, all units should be tested at the same frequency. The DT should consider a reliability standard that has an annual test requirement only that tests all generation units, regardless of type (including intermittent units or stations with multiple units). A region can also develop bi-annual requirements for a summer and winter test if they see a reliability benefit and/or have a market requirement. Concerning R1: The requirement does not specifically state who should receive the generator unit capability data. The PC? The RP?
Response: Thank you for your comments. After thorough consideration of all responses, the SDT has proposed requiring the Generator Owner to verify real power capability data at the same time as reactive power capability data, and proposed merging MOD-024 requirements with MOD-025. In the revised standard, both verifications occur with the same five year re-verification cycle. **The SDT decided to revise the standard and require the Generator Owner to provide the data to the Planning Coordinator – it is then the Planning Coordinator’s responsibility to share the data with other planning entities. The Planning Coordinator has the ability to review past unit performance to insure that the verification value submitted is reasonable, indicative of past unit performance. There is nothing in the standard to prevent the Planning Coordinator from questioning the submitted data.**		
North Carolina Electric Membership Corporation	Yes	R2 is not a requirement as currently written. It is a choice that the RP or PC makes. If he seeks verfied data, then he must provide certain things to the GO. If he chooses to not seek verified data, then he is not required to do anything. This means that M2 is wrong. The RP and PC should not be required to have evidence if they chose not to seek the data. This situation can be fixed by revising R2 to read: "Each Resource Planner and Planning Coordinator shall request verified generating unit Real Power capability data and shall provide each Generator Owner..." R1 requires the GO to submit information but it does not indicate to whom the data should be submitted. We recommend that R1 be changed to read: "Each Generator Owner shall verify the summer and winter Real

Organization	Yes or No	Question 9 Comment
		Power generating capability for each of its units in accordance with MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability and record and submit the information to its Resource Planner and Planning Coordinator via MOD-024-2 Attachment 2 - One-line Diagram, Table and Summary for Verification Information Reporting." Paragraph 2.4 in Att 1: The first word grouping is not a sentence and reads awkwardly. It is suggested that the words "an acceptable value can be obtained" be place in front of the words "by making a temperature". Paragraph 3.4.2 in Att 1: Replace the word "since" with "if" for better clarity. Paragraph 3.4.4 in Att 1: Move the words "in Attachment 2" to the position just after the word "flows". This will make it clear that the sentence refers to flows in Attachments 2 rather than units in Attachment 2.
Response: Thank you for your comments. The SDT did not carry Requirement R2 into the revised standard. **Requirement R1: The revised standard clearly states that the verified data must be provided to the Planning Coordinator. The Planning Coordinator is responsible for sharing its data with other planning entities.** Paragraph 2.4 in Att 1: **The revised standard does not require seasonal (summer and winter) verifications – rather the revised standard requires verifications once every five years.** **Paragraph 3.4.2 in Att 1: this has been replaced with the following for improved clarity:** o **If metering does not exist to measure specific reactive auxiliary load(s), provide an engineering estimate and associated calculations.** **Paragraph 3.4.4 in Att 1: The phrase proposed for clarification is not used in the revised standard.**		
SERC Planning Standards Subcommittee	Yes	R2 is not a requirement as currently written. It is a choice that the RP or PC makes. If he seeks verfied data, then he must provide certain things to the GO. If he chooses to not seek verified data, then he is not required to do anything. This means that M2 is wrong. The RP and PC should not be required to have evidence if they chose not to seek the data. This situation can be fixed by revising R2 to read: "Each Resource Planner and Planning Coordinator shall request verified generating unit Real Power capability data and shall provide each Generator Owner..." R1 requires the GO to submit information but it does not indicate to whom the data should be submitted. We recommend that R1 be changed to read: "Each Generator Owner shall verify the summer and winter Real Power generating capability for each of its units in accordance with MOD-024-2 Attachment 1 - Verification of Summer and Winter Generating Unit Capability and record and submit the information to its Resource Planner and Planning Coordinator via MOD-024-2 Attachment 2 - One-line Diagram, Table and Summary for Verification Information Reporting." R3: The threshhold for reporting a change in MW output is too high. A change of 10 to 50 MW in a generator's

Organization	Yes or No	Question 9 Comment
		output could have an impact to system stability. The threshhold should be a 10 MW change or greater. Paragraph 2.4 in Att 1: The first word grouping is not a sentence and reads awkwardly. It is suggested that the words "an acceptable value can be obtained" be place in front of the words "by making a temperature". Paragraph 3.4.2 in Att 1: Replace the word "since" with "if" for better clarity. Paragraph 3.4.4 in Att 1: Move the words "in Attachment 2" to the position just after the word "flows". This will make it clear that the sentence refers to flows in Attachments 2 rather than units in Attachment 2. The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your comments. The SDT did not carry Requirement R2 into the revised standard. **Requirement R1: The revised standard clearly states that the verified data must be provided to the Planning Coordinator. The Planning Coordinator is responsible for sharing its data with other planning entities.** **Requirement R3: The revised standard does not use a MW threshold as a trigger for reporting a change to verified capabilities – the revised standard uses a threshold of 10% change from the last verified data that is expected to last at least six months. This should limit the reported changes to just those that will be large enough to impact the validity of the models.** **Paragraph 2.4 in Att 1: The revised standard does not require seasonal (summer and winter) verifications – rather the revised standard requires verifications once every five years.** **Paragraph 3.4.2 in Att 1: this has been replaced with the following for improved clarity:** o **If metering does not exist to measure specific reactive auxiliary load(s), provide an engineering estimate and associated calculations.** **Paragraph 3.4.4 in Att 1: The phrase proposed for clarification is not used in the revised standard.**		
NERC Standards Review Subcommittee	Yes	Requirement R1 - The requirement should be clarified that in the case of Joint-owned-units, the Operator of the unit is responsible for verifying the capability of the unit. For R1, R2, & R3, we propose a Violation Risk Factor of “Lower” and a Time Horizon of “Operations Planning, Long-Term Planning”. We propose “Lower” for the VRF because more accurate real power capability values will be assured by this requirement, but reasonably accurate values are likely without this requirement. We propose “Operations Planning, Long-Term Planning” for the TH because RCs and TOPs will use this data in their operations planning studies and PCs and TPs will use this data in their transmission planning studies.

Organization	Yes or No	Question 9 Comment
		For R2, replace "desired temperature to which the data" with "desired ambient coolant temperature to which the summer and winter data" for added clarity.In Attachment 1, 3.2; replace "ambient air temperature" with "ambient coolant (air, water, etc.) temperature" because the capability of different types of generators is affected by the temperature of different cooling medium. In addition, consideration may need to be given to the average pressure level of generating units that use hydrogen for equipment cooling. Introduction, Section 4.2 - As written, small diesel generators at applicable Generating Facilities could be expected to be tested as part of this standard, even if these small generators are intended only for local site power, and are only capable of reaching a 100 KV interconnection by back-feeding through local site distribution circuits and auxiliary transformers. Based on the MVA metrics provided, it would appear their inclusion is not the intent, but the standard is ambiguous as written. On the Implementation Plan for MOD-024-2 for units that are to be verified every five years, they state the verification "will begin five years after the compliance implementation date for annual units." Wouldn't it make more sense to make them verify in the first year after the MOD-24-02 is adopted or approved and then do it every five years after that? On page 2 of 10, A.5. Effective Date, it seems unclear when they say verification "will begin 30 calendar days following the first summer or winter peak period" . For example, if the summer peak occurs in June and you expect a higher peak in July or August and it doesn't occur, then you would be in violation. The same applies for the winter period. They don't define the summer and winter period. On page 5 of 10, MOD-024-2 Attachment 1. 2. Verify generating unit winter gross Real Power generating capability as follows: 2.1. They don't define the winter period and what the conditions should be for the verification test period. Please Clarify. On page 5 of 10, MOD-024-2 Attachment 1. 2. Verify generating unit winter gross Real Power generating capability as follows: 2.4. "by making a temperature correction to the most recent summer gross Real Power generating capability verification." Under what conditions can temperature corrections be made?

Response: Thank you for your comments. After conferring with the Functional Model Working Group, the SDT was directed to change the applicability to Generator Owner based on roles and responsibilities assigned to the Generator Owner.

The SDT is proposing a Lower VRF for both requirements in the revised standard (MOD-024 now merged into MOD-025). However the team did not adopt the suggestion to propose two different time horizons. The data addressed by this standard is limited to data used in planning studies – the data is not provided to any operating entities, just to the Planning Coordinator in the revised standard. Therefore, only the long-term planning time horizon has been proposed.

Several comments identified issues with Requirement R2 in the first draft of MOD-024-2, and the SDT did not carry R2 into the second draft of the standard.

Organization	Yes or No	Question 9 Comment
The SDT modified the applicability section of the standard to more closely align with the criteria in the compliance registry. **The standard was revised to require verification of each applicable unit once every five years – references to annual verification were not carried over into the revised standard and its implementation plan.** **The revised standard does not include any references to seasonal verifications, and doesn't use the terms, "summer period" or "winter period."** **The SDT intended for the unit capability to be adjusted to that expected under the ambient temperature conditions where the PC would model the system. The SDT feels that it would be unreasonable to expect the PC to be able to convert coolant temperature on individual units to capability expected for an ambient temperature as that is best understood by the GO. It is expected that units will be at the nominal hydrogen pressure at which they would normally run. That pressure would not be expected to change during the duration of the test.**		
Independent Electricity System Operator	Yes	The detailed requirements in Attachment 1 are overly prescriptive. Specifically, the requirements listed in Item 3 are too detailed, and most of them are not needed for reliability. We believe Attachment 1 needs only to specify the sustainability (Items 1 and 2), periodicity (Item 4) and the ambient conditions of the verification (some of Item 3). Using the form and the one-line diagram do not contribute to reliability. A requirement to ask for both gross and net capability would suffice.
Response: Thank you for your comments. The SDT believes that attachment one does not contain requirements but provides clarity to the Requirements of the Standard. The SDT felt that providing the diagram would help to clearly show the power flows of each unit and thus contribute to reliability.		
AMEA	Yes	The draft MOD-024-2 removes the decision making ability of the only entities (PC, regions, etc.) that actually know which generators are material to the BES. Instead the draft uses a blanket approach to basically include all generators 20 MVA and above connected at 100 kV and above. This approach will reduce the reliability of the BES due to distraction caused by the deluge of data from a multitude of generators that are not material to the BES and will exempt material generators that are connected below 100 kV.
Response: Thank you for your comments. To determine which generating units to include in the standard, the SDT has adopted the same criteria as used in the compliance registry. Regions are free to include other facilities if they see fit by submitting a request for a variance		
E.ON U.S.	Yes	The first bullet under R2 should be modified as follows: "the desired temperature and/or backpressure to which the data is to be adjusted."Other criteria may also be required during the test. (e.g. MVARs, etc.) Clarify R3 language that 50MW is the change in unit rating - not any unit greater than 50MW. E.ON U.S. questions whether a 50MW threshold for capability change is less meaningful than using a percent of unit capacity threshold. Is the need to report such changes to NERC consistent with any Regional requirement? On Attachment 2, are data measuring points A,B,C and D to be reported as peak or average (over the

Organization	Yes or No	Question 9 Comment
		verification period) values? MOD-024 and MOD-025 are linked and the STD has decided to revise each standard independently. This makes compliance difficult to maintain and test while the two linked standards are undergoing revision.
Response: Thank you for your comments. **Requirement R2: Several comments identified issues with Requirement R2 in the first draft of MOD-024-2, and the SDT did not carry R2 into the second draft of the standard.** **Requirement R3: The revised standard does not use a MW threshold as a trigger for reporting a change to verified capabilities – the revised standard uses a threshold of 10% change from the last verified data that is expected to last at least six months. This should limit the reported changes to just those that will be large enough to impact the validity of the models.** **As currently drafted the data points are to be reported as average.** **The SDT adopted your suggestion and merged MOD-024 and MOD-025 into a single standard (MOD-025).**		
Manitoba Hydro	Yes	The requirement R1 should be rewritten to include derivation of Summer and Winter ratings for Thermal units, and measured capacity corrected to design net head for Hydraulic units. R3 should be clarified to ensure it is only changes greater than 50MW that must be reported, not "any change for units that are greater than 50MW".
Response: Thank you for your comments. **Requirement R1 no longer includes any references to summer or winter ratings. See the revisions to Attachment 1 for additional clarity with respect to verifications for hydro units.** **Requirement R3: The revised standard does not use a MW threshold as a trigger for reporting a change to verified capabilities – the revised standard uses a threshold of 10% change from the last verified data that is expected to last at least six months. This should limit the reported changes to just those that will be large enough to impact the validity of the models.**		
Bauer	Yes	The requirement will result in continuous reporting by the Generator Owner for its hydro units. The capability of hydro units can vary seasonally by more than 50 MW in less than 6 months. It is unclear what reliability purpose is served by this requirement. As stated in the general comment section, Generation capability is forecast, adjusted, and provided to TOP's and BA's under TOP-002-2.
Response: Thank you for your comment. It is not the intent of the standard for continuous reporting by any units. Please see the revised standard – it requires verification of each applicable unit once every five years. For reporting changes to capabilities, the revised standard includes two thresholds that must be met before the Generator Owner is required to report a change in its capabilities – the change must be expected to last more than six		

Organization	Yes or No	Question 9 Comment
months, and second the change must be 10% or more of the last verified capability. These changes should minimize the number of times a change must be reported. **The SDT feels that the data requested under TOP requirements refers to the short time horizon and would be the proper place to report changes in capability based on water levels. Reporting under this standard would be changes in capability due to other plant constraints and are for a much longer planning time horizon.**		
Arizona Public Service Co.	Yes	This standard is contradictory to new NERC policy of "results-based reliability standards." NERC should not be developing a standard which it will have to withdrawa in a future review. If it is decided to go ahead with the standard, the reliabiltity benefits should be expalined.
Response: Thank you for your comment. The reliability-related need for this standard was justified when the SAR was posted for stakeholder review and comment. Results-based requirements are not limited to requirements for real-time system performance.		
We Energies	Yes	Under requirement R3, we question the necessity of reporting a 50 MW reduction in a unit within 15 calendar days of the determination that the reduction is expected to last more than 6 months. Given the current wording, this requirement would need to be understood by a very broad base of individuals who may not typically be aware of this reporting requirement (e.g. a maintenance supervisor evaluating the impact of damage to a mill) and the current wording is unclear as to when the 15 day clock would begin. Prior to making this a requirement, an evaluation should be done to determine how big of a problem this is currently causing to any system modeling, what the risks are of waiting until the next test date to report the issue, and whether or not the concerns change if a RTO has an annual testing requirement.
Response: Thank you for your comments. For reporting changes to capabilities, the revised standard includes two thresholds that must be met before the Generator Owner is required to report a change in its capabilities – the change must be expected to last more than six months, and second the change must be 10% or more of the last verified capability. These changes should minimize the number of times a change must be reported. **Note that in the revised standard, the periodicity for verifying a unit's capabilities is once every five years.** **The SDT believes that with a five year reporting cycle, reporting changes in capability at the next test date would not be adequate.**		
Luminant	Yes	Upon approval of MOD-024, Verification of Real Power and the companion standard MOD-025, Verification of Reactive Power, the applicability to Generator Owners and/or Generator Operators needs to be removed from FAC-008 and FAC-009. With actual verification of Real and Reactive Power, the FAC-008 and FAC-009 requirements become redundant for generators. Attachment 1 verbage needs to be consistent between the words "period" and "season". They are currently used interchangeably.

Organization	Yes or No	Question 9 Comment
		Attachment 1, section 4.5, needs to be expanded so that when a lessor utilized unit is started up, it does not necessarily have to immediately run a maximum capacity test. The unit could have been brought online for capacity and the BA may not allow it to run at maximum output. Emergency situations may preclude running the test. This type of unit should be tested based on a schedule coordinated with the BA. All references to Attachment 2 should also include the "or similar diagram and form" language.
Response: Thank you for your comments. The requirements in FAC-008 and FAC-009 are aimed at providing facility ratings, which may not be the same as a unit's capabilities. **The SDT also agrees with your edits for period and season, and for references to the diagram. The terms, "period" and "season" are not used in Attachment 1 of the revised standard.** **After thorough consideration of all responses, the SDT is proposing that the Generator Owner provide real power verification data at the same time as reactive power verification data, and is proposing to merge MOD-024;s requirements into MOD-025. With the merging of the two standards we are proposing that the real power verification be completed on the same five year frequency as the reactive power verification. This relaxed frequency of testing should allow most units to be scheduled for testing.** **Verification should be performed. The standard does not require units to run for verification only. The SDT believes it is reasonable to assume that the unit will run for at least one hour at maximum capability during the five year period.** **The attachment includes language clarifying that alterations to the diagram are acceptable provided those alterations still include all required information.**		
GO/GOP	Yes	We believe this standard should be retired in its entirety.
Response: Thank you for your comment. Please see the summary consideration of comments in response to Question 1.		
Xcel Energy	Yes	With regard to Attachment 2, the only ambient condition that is required to be reported is ambient air temperature. This has a significant impact on combustion turbines, but little effect on steam turbines. Condenser cooling water temperature has much more impact on steam turbine capability and we feel this should be recorded for that type of prime mover. Also, we would like to request that a description of the process for performing ambient compensation be included either in Attachment 1 or in a separate Technical Guideline to improve the quality and consistency of the information that is reported.
Response: Thank you for your comments. The SDT agrees that ambient temperature has a more significant impact on combustion turbines than steam turbines. The SDT feels that the GO is uniquely qualified to estimate the expected capability of a unit based on ambient temperature or the expected coolant temperature based on sustained ambient temperatures.		

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Draft MOD-026-1 was posted for a 45 day comment period from February 17 – April 2, 2009.

Proposed Action Plan and Description of Current Draft:

This is the first draft of the this standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This second posting is for a 45-day comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post first draft revision of standard.	April-May 2011
2. Post response to comments and third version draft revision of standard.	July – August 2011
3. Post response to comments and request authorization to ballot the revised standard.	September - October 2011
4. Conduct initial ballot.	November 2011
5. Post response to comments.	December 2011
6. Conduct recirculation ballot.	January 2012
7. BOT adoption.	February 2012
8. File with regulatory authorities.	March 2012

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the generator excitation control system and plant volt/var control[1] model (including the power system stabilizer model and the impedance compensator model), and the model parameters used in dynamic simulations accurately represent the generator excitation control systems and plant volt/var control[1] behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

    4.1. Functional entities

    4.1.1 Generator Owner

    4.1.2 Transmission Planner

    4.2. Facilities:

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants with an average capacity factor[2] greater than 5% over the last three calendar years that meet the following:

4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Each generating unit with a gross nameplate rating greater than 100 MVA, connected at the point of interconnection[3] at greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating greater than to 100 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:
    - Each unit with a gross nameplate rating greater than 20 MVA; and
    - The remainder of the plant as an aggregate.

[1] Excitation control system or plant volt/var control system:
a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.
b. For an aggregate generation plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

[2] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date.

[3] The common transmission bus voltage level at which the generator step up transformer is connected.

4.2.2 Generating units connected to the Western Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating greater than 75 MVA, connected at the point of interconnection[3] at greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating greater than 75 MVA, connected at the same point of interconnection with at greater than or equal to 100 kV:
  - Each unit with a gross nameplate greater than 20 MVA; and
  - The remainder of the plant as an aggregate.

4.2.3 Generating units connected to the ERCOT Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating of greater than 50 MVA, connected at the point of interconnection[3] with rating greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating of greater than 75 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:
  - Each unit with a gross nameplate greater than 20 MVA; and
  - The remainder of the plant as an aggregate.

4.2.4 For all interconnections:

- Any technically justified[4] unit requested by the Planning Coordinator.

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, four years following applicable regulatory approval:

- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.
- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6.

5.1.2 By the first day of the first calendar quarter, six years following applicable regulatory approval:

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[4] A technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response.

- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.

5.1.3 By the first day of the first calendar quarter, ten years following applicable regulatory approval:

- Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2.

5.2. In those jurisdictions where no regulatory approval is required:

5.2.1 By the first day of the first calendar quarter, four years following Board of Trustees adoption:

- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.
- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6.

5.2.2 By the first day of the first calendar quarter, six years following Board of Trustees adoption:

- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.

5.2.3 By the first day of the first calendar quarter, ten years following Board of Trustees adoption:

- Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2.

6. Consideration for Early Compliance

6.1. Existing excitation control system and plant volt/var control[1] model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification (provided the model verification addresses the same unit criteria and the same information as required by this standard), or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

B. Requirements

R1. Each Transmission Planner shall provide the following instructions and data to its Generator Owner within 30 calendar days of receiving the request from its Generator Owner for those instructions and data: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Instructions on how to obtain the list of acceptable excitation control system and plant volt/var control function model for use in dynamic simulation.
- Instructions on how to obtain the Transmission Planner's software manufacturer's dynamic excitation control system and plant volt/var control function system model library block diagrams and/or data sheets.
- Any of the Generator Owner's existing unit or plant specific excitation control system and plant volt/var control model data contained in the Transmission Planner's dynamic database from the current in-use models, including generator MVA base.

R2. Each Generator Owner shall provide a verified generator excitation control system and plant volt/var control model (for each of its applicable Facilities) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1 to ensure modeling data is accurate for use in simulation software subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Each Generator Owner shall perform its verifications with one or more models acceptable to its Transmission Planner that collectively include the following information:

2.1.1. Documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance.

2.1.2. Manufacturer, model number (if available), and type of excitation control and plant volt/var control system installed (such as static, ac brushless, dc rotating, volt/var system).

2.1.3. Generator (or plant equivalent) model structure and data (such as reactance, time constants, saturation factors, rotational inertia, or equivalent data).

2.1.4. Excitation control system and plant volt/var system model structure and data for the closed loop voltage regulator.

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used.

2.1.6. Model structure and data for power system stabilizer, if so equipped.

R3. Each Generator Owner shall provide a written response that contains either the technical basis for maintaining the current model, a list of future model changes, or a plan to perform model verification[5] to its Transmission Planner within 90 calendar days of receiving notice of one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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[5] If verification is performed, the 10 year period as outlined in Attachment 1 is reset.

- Written notification, including a technical description from its Transmission Planner of why the excitation control system and plant volt/var control system function model is not “usable” as identified in Requirement R6, Parts 6.1 through 6.3 criteria, or
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system and plant volt/var control system function model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the predicted excitation control system and plant volt/var control function model response did not match the recorded response to a transmission system event.

R4. Each Generator Owner shall provide revised model data or plans to perform model verification to its Transmission Planner within 180 calendar days of making changes to the excitation control system and plant volt/var control system that alter the equipment response[6] characteristic. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R5. Each Generator Owner shall provide a written response to its Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Submit within 90 calendar day’s receipt of the technically justified request.

5.2. Either indicate plans to verify the model or identify the source of revised model data such as:

- Discovery of manufacturer test values to replace generic model data.
- Updating data parameters based on a walk down of the equipment.

5.3. Include corrected excitation control system and plant volt/var control function model data.

R6. Each Transmission Planner shall determine if the verified generator excitation control system and plant volt/control model received meets the criteria identified in Requirement R6 Parts 6.1 through 6.3 and provide a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable. This written response shall be submitted within 90 calendar days of receiving the excitation control system and plant volt/var control verified model information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

[6] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change.

6.1. The excitation control system and plant volt/var control function model can initialize to compute modeling data without error.

6.2. A no-disturbance simulation results in negligible transients.

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control system model exhibiting positive damping.

C. Measures

M1. Each Transmission Planner shall have evidence to show that it provided requested instructions and data (such as dated electronic mail messages or mail receipts) within 30 calendar days of receiving a request as specified in Requirement R1.

M2. Each Generator Owner shall have evidence (such as a dated electronic mail messages or mail receipts) including the verification report to show that it provided the verified generator excitation control system or plant volt/var control model as specified in Requirement R2.

M3. Each Generator Owner shall have evidence to show that it provided a written response (such as a dated copy of the response, or dated electronic mail messages or mail receipts) containing identified information and submitted within 90 calendar days of receiving any written notification as specified in Requirement R3.

M4. Each Generator Owner shall have evidence to show that it provided a written response (such as a dated copy of the request, or dated electronic mail messages or mail receipts) submitted within 180 calendar days of making system changes specified in Requirement R4.

M5. Each Generator Owner shall have evidence to show that it provided a written response (such as dated electronic mail messages or mail receipts) and submitted within 90 calendar days of receiving the request as specified in Requirement R5.

M6. Each Transmission Planner shall have evidence to show that it provided a written response (such as dated electronic mail messages or mail receipts) within 90 calendar days of receiving the model as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest and previous excitation control system and plant volt/var control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 181 calendar days of receiving a request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-026 Attachment 1 but less than or equal to 30 calendar days late; OR The Generator Owner provided the Transmission Planner verified model(s) that omitted one of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted two of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted three of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner failed to provide the verified generator excitation control system or plant volt/var control model(s) or failed to provide the verified model(s) no more than 90 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the six Parts identified in

				Requirement R2, Parts 2.1.1 through 2.1.6.
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving notice. (R3)	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving notice. (R3)	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving notice. (R3)	The Generator Owner failed to provide a written response within 181 calendar days of receiving notice as specified in Requirement R3.. OR The Generator Owner's written response was provided within 181 calendar days of receiving written notice however failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the excitation control system or plant volt/var control[1] system that altered the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the excitation control system or plant volt/var control[1] system that altered the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the excitation control system or plant volt/var control[1] system that altered the equipment response characteristic. (R4)	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 271 calendar days of making changes to the excitation control system or plant volt/var control[1] system that altered the equipment response characteristic as specified in Requirement R4.
R5	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a	The Generator Owner failed to provide a written response to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant as specified in Requirement R5.

	of a unit/plant. (R5)	unit/plant. (R5)	unit/plant. (R5) OR The Generator Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the written response failed to include Requirement R5, Part 5.2 or Part 5.3.	OR The Generator Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the written response failed to include Requirement R5, Parts 5.2 and 5.3.
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R6)	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 120 calendar days but less than 150 calendar days of receiving the verified model information. (R6) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for one of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 150 calendar days but less than 180 calendar days of receiving the verified model information. (R6) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for two of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 181 calendar days of receiving the verified model information as specified in Requirement R6. OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for all specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation and IEEE Working Group on Dynamic Performance of Wind Power Generation, Description and Technical Specifications for Generic WTG models – A Status Report, IEEE PES General Meeting 2011, Detroit, MI, July 24-28
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, “Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, “Dynamic Modeling of GE Wind Plants for Stability Simulations,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, “Description and Technical Specifications for Generic WTG Models – A Status Report,” Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ

9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, “Modeling of GE Wind Turbine-Generators for Grid Studies,” version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, “Field Testing & Model Validation of Wind Plants,” in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, “Experience with Field and Factory Testing for Model Validation of GE Wind Plants,” in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belguim, March/April 2008
13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
14. W.W.Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, “Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations,” Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003

OD-026 Attachment 1

Excitation Control System or Plant Volt/VAr Model Verification Periodicity

Note that local grid codes may specify shorter time frames.

Facility	Condition	Periodicity
Existing Generating Unit	During the eleven calendar year (January - December) transition period and **no exceptions** apply. **OR** During the ten calendar year (January - December) period and n**o exceptions** apply.	A recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard with the verified model and documentation transmitted to the Transmission Planner no more than 365 days from the date that the recorded response was collected.
Existing Generating Unit	During the eleven calendar year (January - December) transition period. **OR** During the ten calendar year (January - December) period. **AND** T**he following exception** applies: 1) Multiple units have the same MVA nameplate rating that are ≤ 350 MVA **AND** 2) The same multiple units have identical applicable components and settings **AND** 3) The same multiple units are sited at the same	Not Required (however, perform verification on a different unit each ten calendar year cycle).

Facility	Condition	Periodicity
	physical location **AND** 4) The model for one of these equivalent units has been verified.	
Existing Generating Unit	Installation of new excitation control system equipment.	A recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 days from the new equipment commissioning date..
Existing Generating Unit	Subjected to an activity resulting in an alteration of the response of the excitation control system.	A recorded response for a voltage excursion shall be collected within 365 days of settings or software changes with the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
Existing Generating Unit	Receive written comments including dated electronic or hard copy evidence indicating that the recorded excitation control system response to a Transmission System event did not match the predicted excitation control system model response.	A recorded response for a voltage excursion shall be collected within 365 days of a written response by the Generator Owner committing to perform model verification with the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
Existing Generating Unit	A model verification plan submitted as a result of a review requested by the Planning Coordinator for an existing Generating Unit.	A recorded response for a voltage excursion shall be collected within 365 days of the submission of a plan to perform model verification as a result of a request for a review from the Planning Coordinator with the verified model and documentation specified in transmitted to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.

Facility	Condition	Periodicity
New or Existing Generator Unit	Excitation control system model identified as unusable by the Transmission Planner. **OR** Receive written comments detailing technical concerns with the Generator Owner's excitation control system model verification documentation.	A recorded response for a voltage excursion shall be collected within 365 days of a written response by the Generator Owner committing to perform model verification with the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
New Generating Unit	New unit installed	A recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit commercial operating date.

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation System Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the excitation system model (including power system stabilizer model and impedance compensator model if so installed) and the model parameters used in dynamic simulations that assess Bulk Electric System (BES) reliability accurately represent generator excitation system behavior.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Operators of generating facilities:

4.1.1.1 Connected to Eastern or Quebec Interconnections with the following characteristics:

Each unit (including synchronous condensers) ≥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 200 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

4.1.1.2 Connected to Western Interconnection with the following characteristics:

Each unit (including synchronous condensers) ≥ 75 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 150 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

4.1.1.3 Connected to ERCOT Interconnection with the following characteristics:

Each unit (including synchronous condensers) ≥ 50 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

Each unit (including synchronous condensers) ≥ 20 MVA within a plant ≥ 100 MVA, connected at the point of interconnection at 100 kV or above and with an average Capacity Factor greater than 5% over the last three calendar years.

4.1.2 Transmission Planners**.**

Proposed Effective Date:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two years following applicable regulatory approval:
  - Each Generator Operator shall verify at least 10% of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, six years following applicable regulatory approval:
  - Each Generator Operator shall verify at least 50% (this includes the units verified in the first year) of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, eleven calendar years following applicable regulatory approval:
  - Each Generator Operator shall verify 100% of its applicable units.

In those jurisdictions where no regulatory approval is required:

- By the first day of the first calendar quarter, two years following Board of Trustees adoption:
  - Each Generator Operator shall verify at least 10% of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, six years following Board of Trustees adoption:
  - Each Generator Operator shall verify at least 50% (this includes the units verified in the first year) of its applicable units per Interconnection on a MVA basis.
- By the first day of the first calendar quarter, eleven calendar years following Board of Trustees adoption:
  - Each Generator Operator shall verify 100% of its applicable units.

B. Requirements

R1. The Generator Operator shall verify the excitation system model (including power system stabilizer model and impedance compensator model if so installed) which represents generator excitation system behavior in dynamic simulations per the following schedules:

1) For a new or existing unit with a new excitation system, within 180 days of the commercial operation date or new equipment commissioning date, whichever occurs first.

2) For an existing unit, once in a ten calendar year period. If multiple units have the same MVA rating that is ≤ 250 MVA, and if they have identical applicable components and settings and are sited at the same physical location, verification of one unit is sufficient for all units. Verification shall be performed on a different unit each ten calendar year cycle.

3) If verification cannot be performed within the ten year period because a unit has not been on-line, the ten year period shall be extended. It is permissible to wait until the unit is scheduled to operate in order to conduct verification so that sufficient advance notice to make arrangements for verification is available. After verification is performed, the subsequent ten year schedule for the next verification will start.

4) For units that reach an average Capacity Factor greater than 5% over the last three calendar years, and have not been verified within the last ten calendar years, verification shall be performed within the next calendar year. The subsequent ten year schedule will start upon a successful verification.

R2. The Transmission Planner shall provide the Generator Operator a set of model data sheets for the acceptable excitation system models (models cannot be confidential or proprietary) for use in dynamic simulation software, with each data sheet including the excitation system model block diagram structure and data requirements, within 30 calendar days of a request from the Generator Operator.

R3. The Transmission Planner shall provide the Generator Operator the unit specific data contained in the Transmission Planner's dynamic database from the current in-use excitation system model, within 30 calendar days of a request from the Generator Operator.

R4. The Generator Operator shall provide to the Transmission Planner the following unit specific information within 90 calendar days of completion of the excitation system model verification:

1) Manufacturer, model number if available, and type of excitation system (for example: static, ac brushless, dc rotating).

2) Generator model structure and data (reactances, time constants, saturation factors, rotational inertia)

3) Excitation system model structure and data for the closed loop voltage regulator (including main exciter if so equipped).

4) Reactive compensation settings (for example: reactive droop, line drop, differential compensation), if utilized.

5) Model structure and data for power system stabilizer, if so equipped.

R5. The Transmission Planner shall determine if the excitation system model is useable by including the excitation system model in dynamic simulation software and substantiating that:

1) A no-disturbance simulation contains no transients.

2) For an otherwise stable simulation, a disturbance simulation results in the equipment exhibiting positive damping.

R6. The Transmission Planner shall inform the Generator Operator whether the excitation system model is useable or not within 90 calendar days of receipt (R4). If the excitation system model is not useable, the Transmission Planner shall provide the Generator Operator with a description of the problem and any relevant details.

R7. The Generator Operator shall provide a written response within 90 calendar days following notification by the Transmission Planner that the excitation system model is not useable. The Generator Operator's response shall either:

- Indicate what changes will be made to the excitation system model, or
- Provide the technical basis why no changes will be made.

R8. The Generator Operator shall provide to the Transmission Planner documentation demonstrating that the excitation system model's response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) within 90 calendar days of completion of the excitation system model verification.

R9. The Generator Operator shall make documentation demonstrating that the excitation system model's response matches the recorded response for a voltage excursion at the generator from either a staged test or a measured system disturbance (i.e., an ambient event) available for inspection and technical review to the Reliability Coordinators, Transmission Operators, and Planning Coordinators that have responsibility for the area in which the associated unit is located, within 60 calendar days after receipt of a request.

R10. The Generator Operator shall provide a written response within 90 calendar days after receipt of a Transmission Planner's or a Planning Coordinator's written comments detailing technical concerns with the Generator Operator's excitation system model verification documentation. That written response shall either:

- Indicate what changes will be made to the excitation system model, or
- Provide the technical basis why no changes will be made.

R11. The Generator Operator shall perform a review of its current excitation system model when its Transmission Operator or Reliability Coordinator provides the Generator Operator dated electronic or hard copy evidence that the recorded excitation control system response to a Transmission system event did not match the predicted excitation system model response. Upon review the Generator Operator shall either:

- Provide a dated electronic or hard copy explanation detailing why the current excitation system model is still appropriate within 90 days to the commenter and the Transmission Planner whose area the generating facility is located in, or
- Perform a re-verification in accordance with R4, and R8 within 180 days. Once the re-verification is performed, the 10 year period as outlined in R1 will be reset.

R12. The Generator Operator shall perform a review of its current excitation system model and model parameters each time an activity that may alter the equipment response is performed. An activity that potentially alters the response of the excitation system and/or power system stabilizer includes but is not limited to:

- Exciter, voltage regulator or power system stabilizer control replacement including software alterations that could alter excitation system equipment response
- Plant Digital Control System addition or replacement

- Plant Digital Control System software alterations that could alter excitation system equipment response
- Exciter, voltage regulator, impedance compensator or power system stabilizer settings change

The Generator Operator shall either:

- Provide documentation that the response has not changed to the Transmission Planner within 90 days of completion of an activity that could have altered equipment response, or
- Perform a re-verification in accordance with Requirements R4 and R8 within 180 days. Once the re-verification is performed, the ten year period as outlined in Requirement R1 is reset.

C. Measures

M1. (To be developed.)

References

The following documents contain technical information beyond the scope of this Standard on excitation system functions, models, and testing

1) IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines

2) IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems

3) IEEE 421.5 IEEE Recommended Practice for Excitation system Models for Power System Stability Studies

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions

Approvals Requested

MOD-026-1 - Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of MOD-026-1:

- Transmission Planner
- Generator Owner

- Facilities

  For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants with an average capacity[1] factor greater than 5% over the last three calendar years that meet the following:

[1] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date.

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Generating units connected to the Eastern or Quebec Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating greater than or equal to 100 MVA, connected at the point of interconnection[2] with rating greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating greater than or equal to 100 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV:
    - Each unit with a gross nameplate rating greater than or equal to 20 MVA; and
    - The remainder of the plant as an aggregate.

Generating units connected to the Western Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating greater than or equal to 75 MVA, connected at the point of interconnection[2] with rating greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV:
    - Each unit with a gross nameplate rating greater than or equal to 20 MVA; and
    - The remainder of the plant as an aggregate.

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating greater than or equal to 50 MVA, connected at the point of interconnection[2] with rating greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV:
    - Each unit with a gross nameplate rating greater than or equal to 20 MVA; and
    - The remainder of the plant as an aggregate.

For all interconnections:

- Any technically justified[3] unit requested by the Planning Coordinator.

[2] The common transmission bus voltage level at which the generator step up transformer is connected.

Effective Date

In those jurisdictions where regulatory approval is required:

By the first day of the first calendar quarter, four years following applicable regulatory approval:

- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.
- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6.

By the first day of the first calendar quarter, six years following applicable regulatory approval:

- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.

By the first day of the first calendar quarter, ten years following applicable regulatory approval:

- Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2.

In those jurisdictions where no regulatory approval is required:

By the first day of the first calendar quarter, four years following Board of Trustees adoption:

- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.
- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6.

By the first day of the first calendar quarter, six years following Board of Trustees adoption:

- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.

By the first day of the first calendar quarter, ten years following Board of Trustees adoption:

- Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2.

[3] A technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements ten years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).

Proposed Action Plan and Description of Current Draft:

This is the second draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This second posting of the standard is for a 30-day formal comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post first draft revision of standard.	April-May 2011
2. Post response to comments and third version draft revision of standard.	July – August 2011
3. Post response to comments and request authorization to ballot the revised standard.	September - October 2011
4. Conduct initial ballot.	November 2011
5. Post response to comments.	December 2011
6. Conduct recirculation ballot.	January 2012
7. BOT adoption.	February 2012
8. File with regulatory authorities.	March 2012

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Frequency Excursion – an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz.

Voltage Excursion – an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage.

A. Introduction

1. **Title:** Generator Performance During Frequency and Voltage Excursions

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure generating units remain connected during frequency and voltage excursions and ensure expected generating unit performance during frequency and voltage excursions is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. The first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption:

   5.1.1 Each Generator Owner shall verify that at least 33% of its applicable units are fully compliant with this standard.

   5.2. The first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption:

   5.2.1 Each Generator Owner shall verify that at least 66% of its applicable units are fully compliant with this standard.

   5.3. The first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption:

   5.3.1 Each Generator Owner shall verify that 100% of its applicable units are fully compliant with this standard.

B. Requirements

R1. Each Generator Owner that has frequency protective relaying [1] activated to trip its new or existing generating unit shall set such protective relaying not to trip per the following operating conditions and relay settings unless the Generator Owner has documented and communicated a non-protection system equipment limitation in accordance with

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (includes frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within excitation controls that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

Requirement R3 for an existing generating unit.[2] *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive.

1.2. During the off-nominal frequency excursions specified in PRC-024 Attachment 1.

1.3. By instantaneous under frequency relays set at a frequency higher than 57.8 Hz.

1.4. By instantaneous over frequency relays set at a frequency lower than 62.2 Hz.

1.5. When the transmission system frequency rate of change is less than 2.5 Hz/second.

R2. Each Generator Owner that has voltage protective relaying activated to trip its new or existing unit or generating plant or Facility shall set its protective relaying not to trip as a result of a voltage excursion (at the point of interconnection) caused by an event external to the plant per the following operating conditions and relay settings unless the Generator Owner has documented and communicated a non-protection system equipment limitation in accordance with Requirement R3 for an existing unit or generating plant or generating Facility: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. When operating within 95% to 105% of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, not to exceed 9 cycles.

2.1.2. If a Transmission Planner’s study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set voltage relays either to the Transmission Planner’s settings or the settings in PRC-024 Attachment 2.

2.1.3. If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relays to trip the generator even if in the “no trip zone” in PRC-024 Attachment 2 is acceptable.

2.1.4. If clearing a system fault necessitates disconnecting a generator, then setting relays to trip the generator even if operating within the “no trip zone” specified in PRC-024 Attachment 2 is acceptable.

R3. Each Generator Owner of an existing generating unit or generating plant or Facility shall document each non-protection system equipment limitation that prevents a generating unit, generating plant, or Facility from meeting the criteria in Requirement R1 or R2 and communicate the documented limitation to its Reliability Coordinator, Planning

[2] To include generators under construction, generators with an executed interconnection agreement or Power Purchase Agreement by the effective date of this standard, or generators with an executed equipment purchase contract and scheduled delivery of major components within 2 years of the effective date of version 1 of this standard.

Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The equipment limitation expires coincident with either of the following conditions:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.
- The generating unit continuous capacity rating increases ≥ 10%.

[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

R4. Within 90 calendar days of receipt of a written inquiry from the Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner regarding an equipment limitation identified in accordance with Requirement R3, the Generator Owner shall provide a written response to the entity that submitted the inquiry.

R5. Each Generator Owner of an existing unit or generating plant or generating Facility shall provide an estimate of that unit's performance during Frequency/Voltage Excursions to the requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated unit) within 30 calendar days of a written request to ensure the accuracy of planning studies and system modeling studies. The documentation shall include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. An estimate of the time duration the existing unit or generating plant or Facility will remain connected as a result of a Frequency Excursion defined by the curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2 or the voltage profile at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault described by dynamic simulation provided by the Transmission Planner if this profile is less stringent than the curves in Attachment 2.

5.2. An estimated probability in 25% increments that the existing unit or generating plant or generating Facility will remain connected during a Frequency Excursion defined by the curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2 or the voltage profile at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault described by dynamic simulation provided by the Transmission Planner if this profile is less stringent than the curves in Attachment 2.

5.3. Identification of the basis for the estimates developed for 5.1 and 5.2 which may include, but is not limited to: experience, actual event histories, or sound engineering judgment.

R6. Each Generator Owner shall design, build, and maintain its new [3] unit or new generating plant or generating Facility so that it will not trip due to a Frequency Excursion or Voltage Excursion at the Point of Interconnection, caused by an event external to the plant, within the parameters set forth in PRC-024 Attachments 1 and 2 and in accordance with the following conditions and exceptions: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

6.1. (condition) When the unit or generating plant or generating Facility is operating at or above the minimum sustainable generation threshold.

6.1.1. For a generating plant or generating Facility consisting of multiple units with total generation > 75 MVA (gross aggregate rating), when the Facility is producing at least 20% of the Facility's rated capacity and the voltage support equipment is in service.

6.2. (condition) For a new generating plant or generating Facility consisting of multiple units less than 20 MVA each with total Facility generation > 75 MVA (gross aggregate rating), at least 90% of the individual generating units shall remain connected.

6.3. (exception) A unit or generating plant or generating Facility may operate to a less stringent voltage ride-through performance criterion than the duration curve identified in PRC-024 Attachment 2 based on the location specific voltage recovery characteristics as specified by the Transmission Planner.

6.4. (exception) A unit or generating plant or generating Facility may trip if this action is designed as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).

6.5. (exception) A unit or generating plant or generating Facility may trip if clearing a system fault necessitates disconnecting the unit or generating plant or generating Facility.

6.6. (exception) A unit or generating plant or generating Facility may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation.

6.7. (exception) A unit or generating plant or generating Facility may trip if the protective functions (such as out of step or loss of field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

R7. Each Generator Owner shall provide to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner (that monitors or models the associated unit) its generator protection trip settings as specified by Requirements R1

[3] Excluding generators in service prior to the effective date of version 1 of this standard and excluding generators referenced in Footnote 2.

and R2, and documented equipment limitations as specified by Requirement R3 within 30 calendar days of any change to those trip settings or limitations and within 30 calendar days of a written request for the data to ensure the accuracy of planning studies and system modeling. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner has evidence such as dated setting sheets, calibration sheets, or other documentation, that generator frequency protective relays have been set in accordance with Requirement R1.

M2. Each Generator Owner has evidence such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies, that generator voltage protective relays have been set in accordance with Requirement R2.

M3. Each Generator Owner has evidence that it has documented and communicated any equipment limitations (Protection System excluded) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

M4. Each Generator Owner has evidence such as dated e-mails, mail receipts or other evidence that it provided a written response to an inquiry regarding equipment limitations to a requesting entity within 90 calendar days of a request in accordance with Requirement R4.

M5. Each Generator Owner has evidence such as a copy of the performance report and dated e-mails, mail receipts or other documentation that an estimate of the performance of its existing generating unit(s) as a result of a Frequency Excursion or Voltage Excursion has been communicated in accordance with Requirement R5.

M6. Each Generator Owner has evidence such as dated unit output records, trip investigation reports or disturbance monitoring records or a trip report indicating each unit trip did not result from a Frequency Excursion or Voltage Excursion as specified in Requirement R6 or provide an attestation that the generating unit, generating plant or Facility did not trip.

M7. Each Generator Owner has evidence such as dated e-mails, mail receipts or other evidence that it communicated generator protective relay settings or equipment limitations to a requesting entity within 30 calendar days of a request or change in setting(s) in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest evidence of Requirement R1 through R7, Measure M1 through M7; and shall retain prior evidence for 3 calendar years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner failed to set frequency protective relaying so that it does not trip within the criteria listed in Requirement R1, Parts 1.1 through 1.5.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying failed to set its protective relaying not to trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the operating conditions and relay settings specified in Requirement R2
R3	The Generator Owner documented the non-protection system equipment limitation that prevents compliance with Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 30 calendar days but less than or equal to 40 calendar days of identifying the limitation.	The Generator Owner documented the non-protection system equipment limitation that prevents compliance with Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 40 calendar days but less than or equal to 50 calendar days of identifying the limitation.	The Generator Owner documented the non-protection system equipment limitation that prevents compliance with Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 50 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner failed to document any non-protection system equipment limitation that prevents compliance with Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Planner within 61 calendar days of identifying the limitation.
R4	The Generator Owner provided a written response to an equipment limitation inquiry more than 90 calendar days but less than or equal to 100 calendar days of a written request.	The Generator Owner provided a written response to an equipment limitation inquiry more than 100 calendar days but less than or equal to 110 calendar days of a written request.	The Generator Owner provided a written response to an equipment limitation inquiry more than 110 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner failed to provide a written response to an equipment limitation inquiry within 121 calendar days of a written request.
R5	The Generator Owner provided an estimate of a unit's performance more than 30 calendar days but less than or equal to 40 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 40 calendar days but less than or equal to 50 calendar days of a written request. OR The Generator Owner failed to include documentation for one of the Parts specified in Requirement R5, Parts 5.1 through 5.3.	The Generator Owner provided an estimate of a unit's performance more than 50 calendar days but less than or equal to 60 calendar days of a written request. OR The Generator Owner failed to include documentation for two of the Parts specified in Requirement R5, Parts 5.1 through 5.3.	The Generator Owner failed to provide an estimate of a unit's performance within 61 calendar days of a written request. OR The Generator Owner failed to include any of the documentation specified in Requirement R55, Parts 5.1 through 5.3.
R6	N/A	N/A	N/A	The Generator Owner failed to demonstrate its new unit or new generating plant or generating Facility did not trip due to a Frequency Excursion within the parameters set forth in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Requirement 6. OR The Generator Owner failed to demonstrate its new unit or new generating plant or generating Facility did not trip due to a Voltage Excursion within the parameters set forth in Attachment 2.
R7	The Generator Owner provided its generator protection trip settings as specified by Requirements R1 and R2, and documented equipment limitations as specified by Requirement R3 more than 30 calendar days but less than or equal to 40 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings or equipment limitations more than 30 calendar days but less than or equal to 40 calendar days of a	The Generator Owner provide its generator protection trip settings as specified by Requirements R1 and R2, and documented equipment limitations as specified by Requirement R3 more than 40 calendar days but less than or equal to 50 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings or equipment limitations more than 40 calendar days but less than or equal to 50 calendar days of a	The Generator Owner provide its generator protection trip settings as specified by Requirements R1 and R2, and documented equipment limitations as specified by Requirement R3 more than 50 calendar days but less than or equal to 60 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings or equipment limitations more than 50 calendar days but less than or equal to 60 calendar days of a	The Generator Owner failed to provide its generator protection trip settings as specified by Requirements R1 and R2, and documented equipment limitations as specified by Requirement R3 within 61 calendar days of any change to those trip settings or limitations. OR The Generator Owner failed to provide trip settings or equipment limitations within 61 calendar days of a written request for the data.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	written request.	written request.	written request.	

E. Regional Variances

None

F. Associated Documents

None

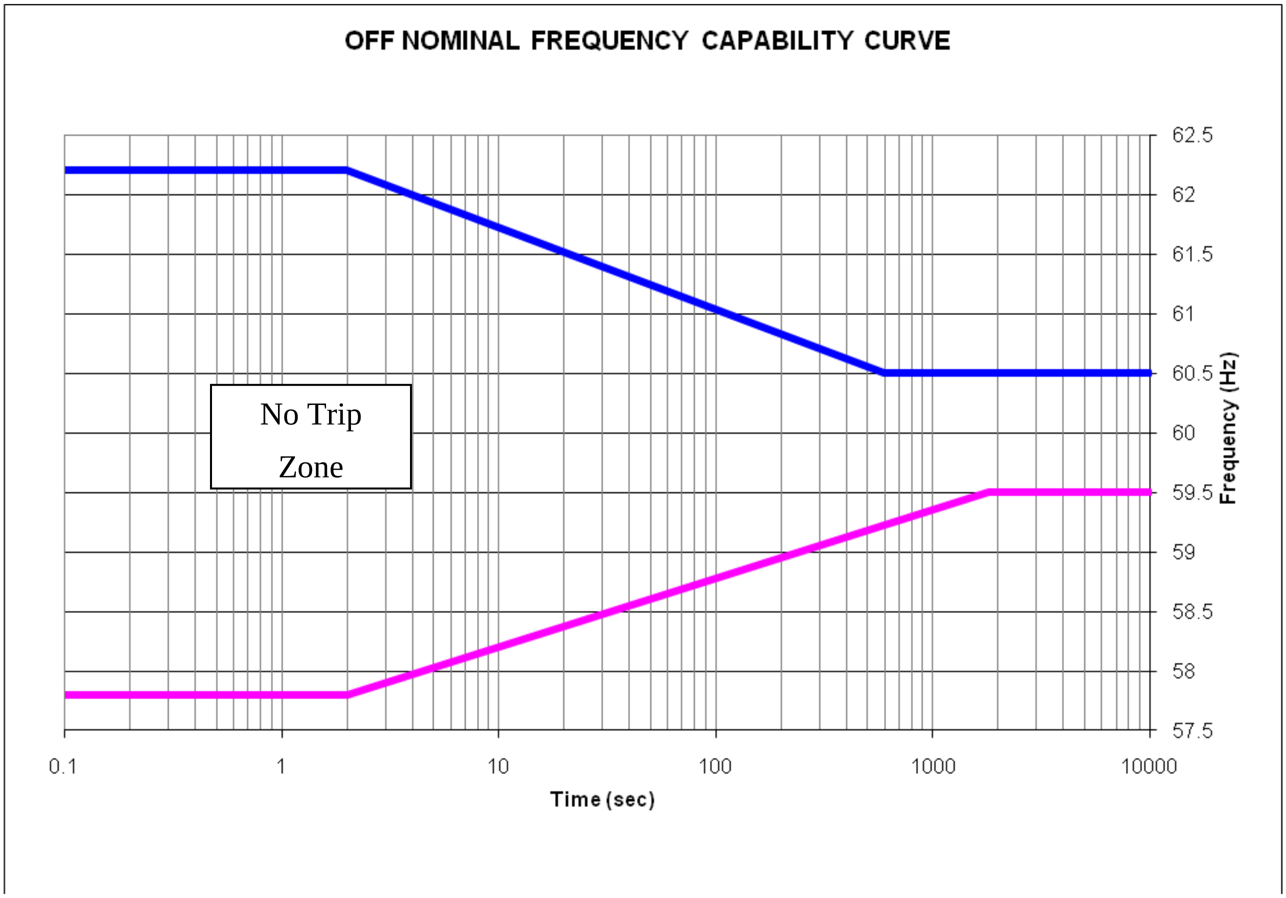
Version History

Version	Date	Action	Change Tracking

G. References

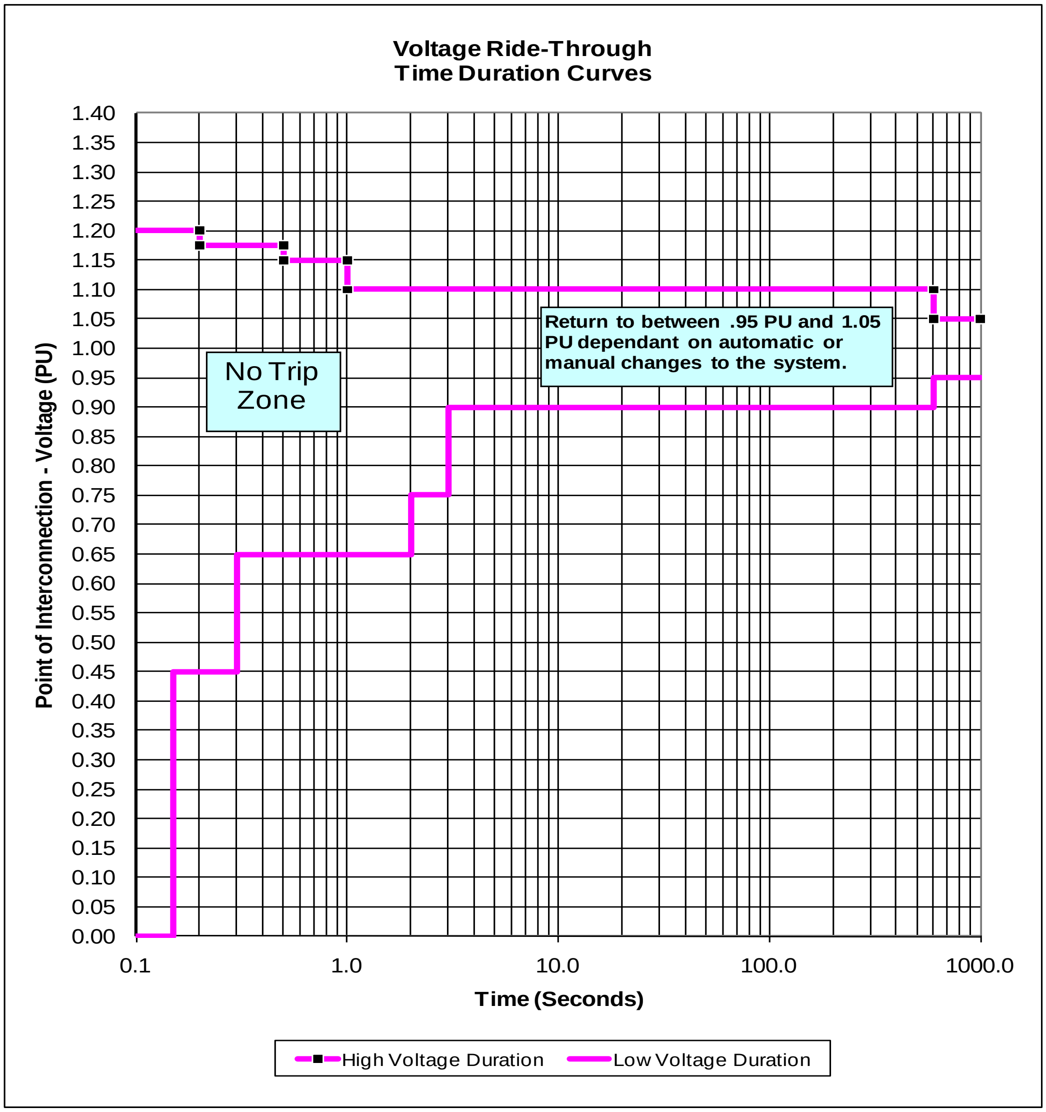
1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1



Frequency (hertz)	57.8	59.5	62.2	60.5
Time (seconds)	0 to 2	Over 1800	0 to 2	Over 600

PRC-024— Attachment 2



Curve Data Points:

HVRT DURATION	
Time (Sec)	**Voltage (p.u.)**
0.20	1.200
0.50	1.175
1.00	1.150
600	1.100

LVRT DURATION	
Time (Sec)	**Voltage (p.u.)**
0.15	0.000
0.30	0.450
2.00	0.650
3.00	0.750
600	0.900

Voltage Ride-Through Curve Clarifications

1. The per unit voltage base for these curves is the scheduled operating voltage as measured at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted apply to a three-phase transmission system zone 1 fault with Normal Clearing.
3. When the cumulative voltage duration at the point of interconnection with the BES is within the voltage boundaries of these curves, the generator voltage protective relaying will not trip the generator.
4. The curves depicted assume system frequency is 60 Hertz.
5. Use the following assumptions if basing voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating,
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging.
    d. Scheduled voltage is measured at the point of interconnection.
6. Calculate voltage protection relay settings to comply with these curves assuming that any additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
7. Calculate voltage protection relay settings to comply with these curves, accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

SAR authorized by Standards Committee for development as a reliability standard July 12, 2007.

Standard Drafting Team appointed by Standards Committee September 11, 2007.

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard and includes requirements with violation risk factors, time horizons and measures; additional compliance elements will be added later. This first posting of the standard is for a 45-day comment period from February 17 through April 2, 2009.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and second version of standard.	May 4, 2009
2. Post response to comments and request authorization to ballot the revised standard.	To be determined
3. Conduct initial ballot.	To be determined
4. Post response to comments.	To be determined
5. Conduct recirculation ballot.	To be determined
6. BOT adoption.	To be determined
7. File with regulatory authorities.	To be determined

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**

2. **Number:** PRC-024-1

3. **Purpose:** Ensure that generator frequency and voltage protective relays[1] are set to support transmission system stability during voltage and frequency excursions.

4. **Applicability**

   4.1. Functional entities:

   4.1.1 Generator Owners

   4.2. Facilities:

   4.2.1 Each generating unit (with installed voltage or frequency protective relays) greater than 20 MVA connected to the Bulk Electric System (BES).

   4.2.2 Each unit (with installed voltage or frequency protective relays) at generating plants/facilities consisting of multiple units with total generation > 75 MVA (gross aggregate nameplate rating) at the point of interconnection to the BES.

5. **Effective Dates:** The standard is effective the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC BOT adoption in those jurisdictions where regulatory approval is not required).

   Each Generator Owner's unit with installed voltage or frequency protective relays shall be compliant with the standard based on the following phased implementation schedule:

   5.1. No less than 33% of a Generator Owner's units shall be fully compliant with the standard within 1 year of the effective date of the standard.

   5.2. No less than 66% of a Generator Owner's units shall be fully compliant with the standard within 2 years of the effective date of the standard

   5.3. No less than 100% of a Generator Owner's units shall be fully compliant with the standard within 3 years of the effective date of the standard

A. Requirements

R1. Each Generator Owner shall set its installed generator frequency protective relaying not to trip during the following frequency-related operating conditions unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5: *(Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA) (Time Horizon – Operations Planning)*

R1.1. When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive.

R1.2. During the off-normal frequency excursions specified in PRC-024-1 Attachment 1.

R1.3. Instantaneous underfrequency relay trip setting shall be set no higher than 57.8 Hz.

R1.4. Instantaneous overfrequency relay trip settings shall be set no lower than 62.2 Hz.

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[1] Includes voltage and frequency protective functions for discrete relays, multi-function protective devices, voltage regulators, etc.

R2. Each Generator Owner shall set its installed generator over and under voltage (including volts per hertz relays evaluated at nominal frequency) protective relays not to trip during the steady-state and voltage-related operating conditions as follows unless the Generator Owner has documented and reported the unit's limitation in accordance with Requirement R5 of this standard: *(Violation Risk Factors: High - Units ≥500 MVA; Medium - Units >100 MVA and <500 MVA; Lower - Units ≤100 MVA) (Time Horizons – Operations Planning)*

R2.1. When operating within 95% to 105% of rated generator terminal voltage.

R2.2. During the transient voltage excursions measured at the point of interconnection to the BES as specified in PRC-024-1 Attachment 2. The following generator protective relaying settings are acceptable:

R2.2.1. For three-phase transmission system zone one faults with Normal Clearing, relaying may be set based on actual fault clearing times, but not greater than nine cycles.

R2.2.2. Relaying may be set to meet a shorter voltage ride through duration curve as specified by the Transmission Planner based on the location specific voltage recovery characteristics.

R2.2.3. Relaying may be set to trip a generator after fault initiation if this action is intended as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).

R2.2.4. Relaying may be set to trip a generator if clearing a system fault necessitates disconnecting the generator.

R3. Each Generator Owner shall provide to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners (that monitor or model the associated unit) its generator protection trip settings as specified by Requirement R1 and Requirement R2 within 30 calendar days of any change to those trip settings. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*

R4. Each Generator Owner shall provide to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners (that monitor or model the associated unit), its generator protection trip settings as specified by Requirement R1 and Requirement R2 within 30 calendar days of a written request for the data. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*

R5. If an existing generator unit[2] cannot meet either Requirement R1 or Requirement R2 due to equipment limitations, such as manufacturer warranty requirements or limitations that endanger the equipment according to published manufacturer instructions, (Protection System excluded), the Generator Owner is granted an exception for that unit from meeting the portion of Requirement R1 or R2 for that limitation once it provides documentation of the equipment limitation(s) to the Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners that monitor or model the associated unit, within 30 days of identifying the equipment limitation. *(Violation Risk Factors: Medium - Units >100 MVA; Lower - Units ≤100 MVA) (Time Horizon – Operations Planning)*

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[2] Including generators under construction, generators with an executed interconnection agreement or Power Purchase Agreement, or generators with an executed equipment purchase contract and scheduled delivery within 2 years of the effective date of the standard.

The exception for the equipment limitation shall expire coincident with either of the following conditions:

- The equipment causing the limitation is replaced with equipment that removes the technical limitation.
- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10%.

R6. The Generator Owner shall provide a written response within 90 calendar days of receipt of written comments from a Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner (that monitors or models the associated unit) regarding the equipment limitation. The response shall indicate whether a change will be made to the equipment limitation or if no change will be made to the equipment limitation, the reason why. *(Violation Risk Factor – Lower) (Time Horizon – Operations Planning)*

B. Measures

M1. Each Generator Owner shall have evidence such as setting sheets, calibration sheets, or other documentation, that generator frequency protective relays have been set in accordance with Requirement R1.

M2. Each Generator Owner shall have evidence such as setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies, that generator voltage protective relays have been set in accordance with Requirement R2.

M3. Each Generator Owner shall have evidence such as dated e-mails, mail receipts or other documentation that generator protective relay settings changes have been communicated to the entities listed in Requirement R3.

M4. Each Generator Owner shall have evidence such as dated e-mails, mail receipts, request received or other documentation that generator protective relay settings have been communicated to the entities listed in Requirement R4.

M5. Each Generator Owner of existing generators that are unable to comply with Requirements R1 or R2 due to equipment limitations (Protection System excluded) shall have evidence such as warranty agreements, insurance agreements, manufacturers documented limitations, engineering analysis or other documentation that explains the equipment limitation of the unit(s).

M6. Each Generator Owner shall have evidence such as dated copy, e-mail receipts or other evidence that it provided a written response to a commenting entity within 90 calendar days of receipt of comments.

C. Regional Variances

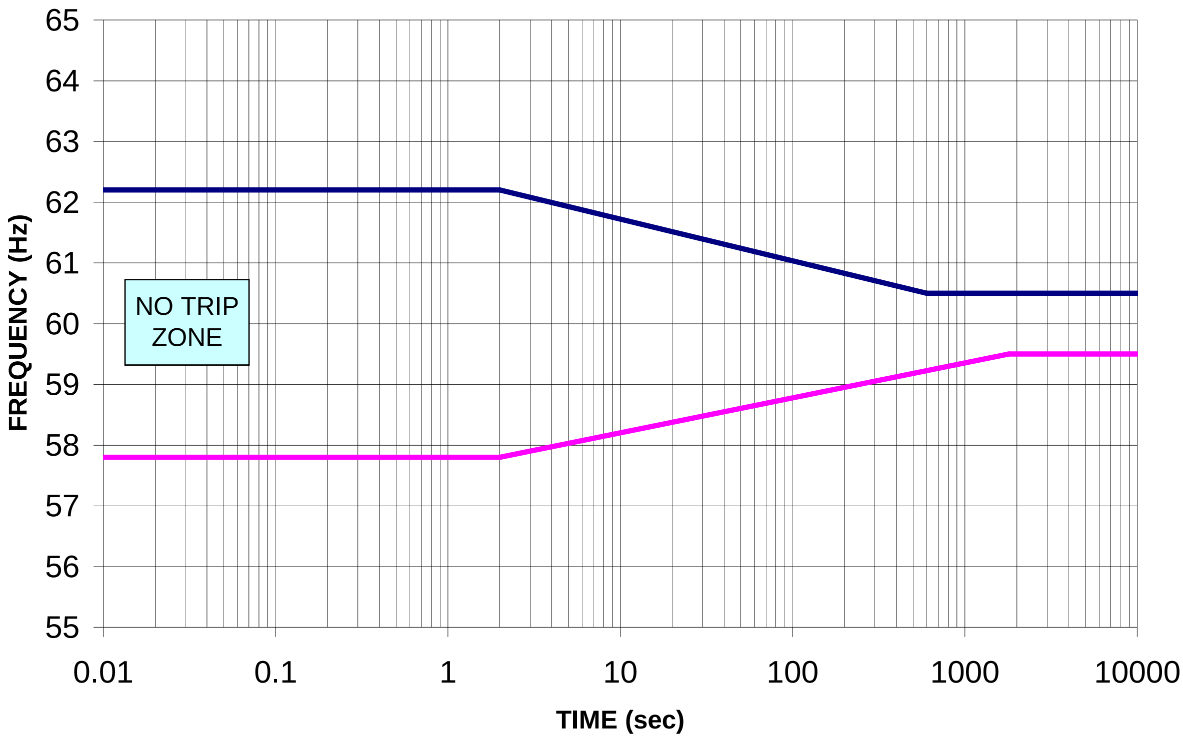
None

D. References

"The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

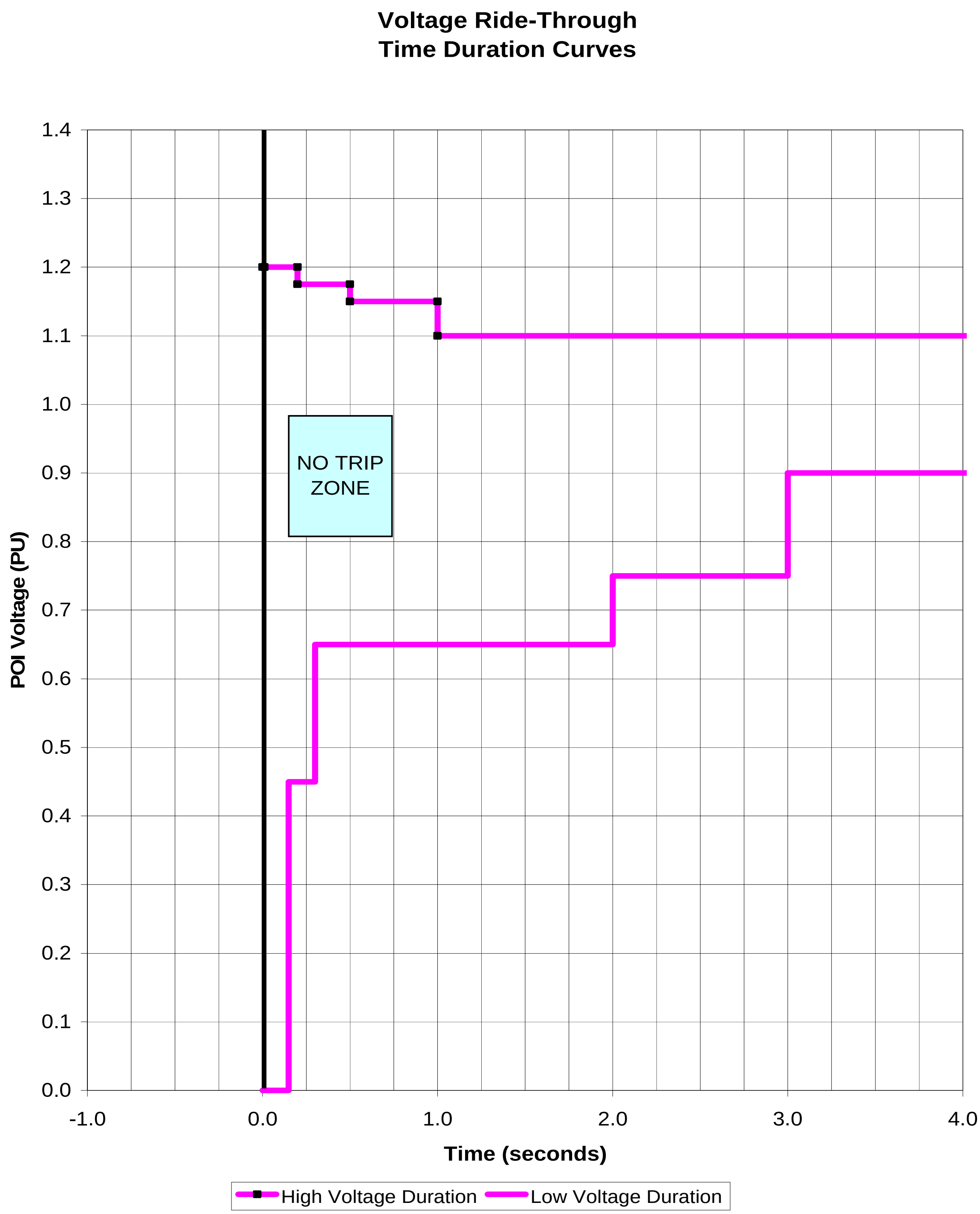
PRC-024-1 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Frequency (hertz)	62.2	60.5	57.8	59.5
Time (seconds)	0 to 2	600 to 10,000	0 to 2	1,800 to 10,000

PRC-024-1 — Attachment 2



The following data points would apply to this curve:

HVRT DURATION		LVRT DURATION	
Time	Voltage	Time	Voltage
0.20	1.200	0.15	0.000
0.50	1.175	0.30	0.450
1.00	1.150	2.00	0.650
4.00	1.100	3.00	0.750
		4.00	0.900

Voltage Ride-Through Curve Clarifications

1. The per unit voltage base for this curve is the nominal operating voltage as measured at the point of interconnection to the BES.
2. As long as the cumulative voltage duration at the point of interconnection with the BES is within the voltage boundaries of the curve, the generator voltage protective relaying will not trip the generator.
3. The curve depicted in this Attachment 2 assumes system frequency of 60 Hertz and all of the units connected to the same transformer are on line.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for PRC-024-1, Generator Performance During Frequency and Voltage Excursions

Approvals Requested:

PRC-024-1 – Generator Performance During Frequency and Voltage Excursions

Definitions:

Frequency Excursion – an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz.

Voltage Excursion – an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage.

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of PRC-024-1:

- Generator Owner

Effective Date

The first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption:

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

- Each Generator Owner shall verify at least 33% applicable units fully compliant with this standard.

The first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption:

- Each Generator Owner shall verify at least 66% applicable units fully compliant with this standard.

The first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption:

- Each Generator Owner shall verify 100% applicable units fully compliant with this standard

The phasing allows Generator Owners to effect any needed changes to the protective system settings during normally scheduled outages.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1, R4 will also go into effect.

Unofficial Comment Form for Generator Verification (Project 2007-09)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the Second Posting of MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Project 2007-09). The electronic comment form must be completed by **August 1, 2011.**

Project 2007-09 Generator Verification

If you have questions please contact Stephen Crutchfield at Stephen.Crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The purpose of Project 2007-09 - Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).

- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024-1 — Verification of Generator Gross and Net Real Power Capability.

- MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability.

And four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007.

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit
- Capabilities and Protection

- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions

- MOD-027-1 — Verification of Generator Unit Frequency Response

This is the second posting of standard MOD-026-1 Verification of Models and Data for Generator Excitation Control System Functions for industry review. It should be noted that the title of the standard has been changed from "Verification of Models and Data for Generator Excitation Control System Functions" to "Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions" in order to reflect the SDTs inclusion of plants with several small units, in large part to include Variable Energy

Resource plants (discussed in more detail below). The second posting of standard MOD-026-1 Verification of Models and Data for Generator Excitation Control System Functions was developed with consideration of industry response to questions that were posed as part of the Comment Form accompanying the first posting. This posting also includes the initial posting of standard MOD-027-1. Note for the same reason discussed for standard MOD-026-1, standard MOD-027-1 has been re-titled from “Verification of Generator Unit Frequency Response” to “Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions”. While there are a few differences between standards MOD-026-1 and MOD-027-1 as detailed below, there are also many similarities. The two standards are similar in both substance and style.

Standard MOD-026-1:
One of the major issues that the SDT presented to industry during the first posting was the functional entity “applicability”. The SDT recognized that assigning responsibility to appropriate entities for a continent wide standard for verifying unit excitation system models would be difficult. In the first posting of the standard, the SDT selected the Generator Operator to be the appropriate entity to be responsible for verifying the model. However, industry feedback from the first posting indicated that the majority of industry participants felt that the Generator Owner was the appropriate entity to assign responsibility. The SDT also consulted with the NERC Functional Model Working Group (FMWG) which felt that the Generator Owner was the appropriate entity to assign model verification responsibility. Therefore, in this second posting of standard MOD-026-1, the responsibility for model verification has been assigned to the Generator Owner. As such, it is up to the Generator Owner and Generator Operator to define contractual arrangements needed to comply with the requirements of this standard.

A significant change incorporated into the second posting of this standard is a proposed process where the Planning Coordinator can request a review of an excitation control system model. Many of the affirmative responses from industry qualified their answer by stating that the process needs to be well defined. As such, the new Requirement (R5) requires the Planning Coordinator to supply technical justification for the request. If upon receipt of this notification the Generator Owner has revised excitation control system model data, then the Generator Owner can supply that data to the Planning Coordinator. An example might be the discovery of unit specific “as-commissioned” manufacturer data which would be more accurate than generic manufacturer data. If better data is not available, or does not address the Planning Coordinator’s dynamic modeling and stability performance needs, then the Planning Coordinator can request the Generator Owner to review the excitation control system model and provide revised data. Since the Generator Owner has already provided updated data to the degree possible without verifying the model, then the Generator Owner would be required to verify the model within the time frame specified in the Periodicity Table (one year to obtain a recorded response of a voltage excursion and submission of the model within 180 days after obtaining the recorded response).

The SDT also asked industry several questions pertaining to the extent facilities are to be verified, including periodicity for model verification. As a baseline, the SDT recognized that the excitation system models and model data are already collected through the processes identified in standards MOD-012 and MOD-013. This information, with few exceptions, already establishes a quality dynamics database. However, as confirmed through field testing, performing verification activities specified in the draft standard will improve the accuracy of exciter models used in dynamic simulation. Major themes expressed by industry and subsequent action taken by the SDT include:

1. The present draft of the standard maintains a base Applicability requiring verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection (refer to Item 5 below). The present draft of the standard does clarify that the connected MVA threshold for plants is to include units connected at the same point of interconnection. For example, if a plant site has generators interconnected to two different transmission voltage levels, the MVA threshold would be applied based on the cumulative MVA of the generators interconnected at each transmission voltage level.
2. The majority of industry agreed with the 5% capacity factor threshold. The application of the capacity factor threshold has been clarified in the new Periodicity Table.
3. The majority of industry agreed with the philosophy of allowing excitation control system verification for a single unit to satisfy compliance for other units if certain conditions are met (such as having the same MVA rating, having identical applicable components and settings, and being sited at the same physical location); which remain unchanged in the present draft of the standard.
4. Based on industry comments and technical justification regarding the nameplate MVA of steam units for existing Combined Cycle plant technology, the SDT raised the threshold MVA nameplate rating from ≤250 MVA to ≤350 MVA.
5. Industry agreed with the general ten year periodicity timeframe proposed. It was pointed out to the SDT that periodicity alone did not constitute a standalone reliability requirement. Therefore, R1 from the previous draft of the standard has been removed and replaced with a Periodicity Table. The Periodicity Table provides the base ten year applicability timeframe for collecting data needed to perform the verification, and adds an additional year to perform the verification analysis. The Periodicity Table also addresses scenarios which could require additional testing and subsequent model re-verification. The Periodicity Table will enable Generator Owners to quickly determine required retest dates for model verification.
6. Several industry responders asked if the standard was applicable to wind generation. As detailed in the Response to Comments document posted on the NERC website, the Applicability section MVA threshold in the first posting of standard MOD-026 resulted in wind powered units not being subject to this standard because individual wind units are not rated greater than 20 MVA. However, since there are an increasing number of wind farms with significantly larger aggregate MVA, their impact on the reliability of the Bulk Electric System cannot be ignored; otherwise, a reliability gap would exist. Therefore, as requested by industry, the SDT discussed the possibility of requiring verification of dynamic models that represent the aggregate of numerous small units and necessary auxiliary equipment required of the technology. This could include plant dynamic voltage control and reactive support of all the units and auxiliary equipment (such as individual WTG response, plant-wide volt/var controller response, and response from separate volt/var regulation devices contained in the plant such as SVC/STATCOM/Synchronous Condenser) contained in any technology generation plant, including a wind farm (plant), that exceeds the aggregate nameplate MVA threshold specified. There are dynamic models that adequately replicate performance for some wind units today. However, there are many existing wind units which do not have publicly available models supplied by the Original Equipment Manufacturer. Generic wind models (i.e., type I, II, III and IV) are in various stages of development. Also, there are ongoing efforts involving Regional Entities and manufactures to close any large gaps that may exist in current generic models. Thus, the SDT believes that generic wind farm

(plant) models will reach an appropriate state of maturity for establishing boundary conditions in Bulk Electric System Studies in advance of the eventual effective date of this standard. Therefore, to mitigate this reliability gap, the Applicability section has been expanded in the second posting of the standard to include a significant MVA percentage of all generation of all technologies. Specifically, based on review of in-service wind farm plant data, that includes approximately 80% of the wind farm plant MVA capacity in each Interconnection, the MVA threshold for plants was decreased from 200 MVA to 100 MVA for the Eastern and Quebec Interconnections, 150 to 75 MVA for the WECC Interconnection, and from 100 to 75 MVA for the ERCOT Interconnection (note – reducing the MVA threshold for plants in ERCOT any further would have exceeded the NERC Compliance Registry criteria. The 75 MVA plant threshold specified includes more than 80% of the wind farms in ERCOT). Additionally, the language makes clear that plant units less than 20 MVA should be verified in aggregate when possible.

The SDT drafted the first posting of the standard with minimal technical specificity so that either traditional staged testing, or ambient monitoring and other future techniques could be refined and utilized while still satisfying the Requirements. The SDT drafted a standard that concentrates on stating "what is required" but without stating "how to accomplish what is required", with peer review processes. Based on industry comments, the present draft of the standard maintains this same philosophy.

Several industry responders pointed out that the first posting version of the draft standard arguably contained non-reliability related requirements, and/or the chronological and procedural style resulted in a cumbersome document that was hard to follow. With this feedback, the SDT refined the standard to contain only reliability related requirements. This effort resulted in the creation of a Periodicity Table which is an attachment to the draft standard but is not a standalone requirement. Also, activities that are expected to occur infrequently, such as the "peer review" process, have been incorporated into Requirement Parts that are not intermingled with the 10 year periodic model verification base tasks. The SDT also combined all information the Generator Owner has to provide the Transmission Planner following successful model verification into a single section (reference requirement R2, Parts 2.1.1 through 2.1.6 of the revised standard). This information also includes the generator model data used in the excitation control system verification process however, the SDT stopped short of requiring generator model data verification. The majority of industry comments indicated a separate SAR would be required for a generator model verification standard.

The SDT discussed if standard MOD-026-1 should also include verification of excitation control systems of synchronous condensers[1]. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. There is no peer review requirements incorporated into standard MOD-025 which address steady state modeling thus, the inclusion of synchronous condensers in

[1] Note this does not include hydro generators which can operate in a "synchronous condenser" mode. If this mode of operation is expected, then the model should reflect this operating state.

standard MOD-025 is a better fit. Also, if Transmission Owners decide to pay for synchronous condenser installation and maintenance, which by its very nature does not generate Real Power as a source of revenue, then by default the apparatus is installed for dynamic voltage support; most likely to extend a dynamic voltage security limit. Therefore, the Transmission Owner should be highly motivated to understand and model synchronous condenser dynamic behavior. Therefore, the SDT decided that if there is a need to develop a Reliability Standard to model the expected dynamic behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.

The first posting of the draft standard proposed an implementation plan requiring 10% of a Generator Owner's applicable units to be verified within two years following standard approval, 50% within six years following standard approval, and 100% within eleven years following standard approval. Concern was raised regarding the start up time to establish processes that this standard would require. For this concern, the SDT decided to extend the timeframe following standard approval for the first set of models required to be verified from "after 2 years of regulatory approval, 10% of its applicable units per Interconnection on a MVA basis" to "…four years following applicable regulatory approval….Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2." In addition to allowing entities additional start up time to develop this expertise, the new timeline allows traditional staged testing to be performed concurrent with the planned maintenance outage schedule. The language "being compliant with R1" means that suitable voltage excursion data has to be collected per the Periodicity Table. Entities actually have an additional year to analyze the voltage excursion data to verify the model and communicate the results to the Transmission Planner. Finally, the SDT has accepted the recommendation to allow verification of excitation system model(s) with established Regional Entity procedures and guidelines for demonstrating compliance with this new standard if the verification is completed within 10 years of standard approval (reference the proposed Implementation Plan).

Differences also exist between MOD-026-1 and MOD-027-1:

1) The implementation plan for standard MOD-027-1 is structured to recognize that Generator Owners will either need to install equipment to record the real power output of units during an appropriate frequency excursion or modify the existing recording equipment (such as frequency triggers, recording time, etc.). The proposed implementation plan specifies compliance with R2 at intervals of 25% of applicable units per Interconnection on a MVA basis three years after the effective date, 50% at five years, 75% at seven years, and 100% at nine years. Compliance with R2 as per the Periodicity Table (Table 1), means that beginning on the implementation date, the Generator Owner has 10 years to obtain an appropriate recorded response, and 2 years after obtaining the appropriate recorded response to verify the model (see Item 4 below that discusses exceptions to the aforementioned timeframe).

2) Like the draft standard for verification of excitation control system models, this draft standard allows for both staged tests and for ambient monitoring. However, the SDT expects that the majority of turbine/governor and load control functions will be verified through ambient monitoring. To ensure the impact of outer loop controls is captured and replicated in the model, the standard allows

staged tests where a frequency reference change is applied if the unit is on-line. This type of test is not common. Many units do not have a frequency reference change input where such a signal can be applied. Therefore, the SDT recognized that the Generator Owner's opportunity to verify that the predicted model response matches the recorded response for an appropriate system frequency excursion will often be dependent on its unit being on-line and in an operating state to respond to the system frequency excursion when it occurs. The basis for this strategy is:

a. Large economical units have a higher probability of being on-line in a proper operating state to experience a frequency excursion requiring model verification.
b. Units which are not on-line or not in a proper operating state will not help arrest the frequency excursion. Even if this is not the case, it is better to experience an event for model verification as opposed to relying on a survey that may be inaccurate.

3) In the current draft of MOD-026, the Generator Owner has one year from the capture of a voltage excursion to verify the excitation control system model. This timeframe is based on the SDT's belief that the majority of exciters will be verified using a staged test; and if ambient monitoring is utilized, there will be frequent naturally occurring transmission system voltage excursions. Since the SDT anticipates that the majority of the units' turbine/governor and load control models will be verified utilizing ambient monitoring, it is recognized that it is appropriate to give the Generator Owner time to retrieve captured data. Unlike ambient voltage excursion data needed for excitation control system model verification, the unit must be in an operating state that would allow the unit to respond to the frequency excursion. Also, it is likely that the number of acceptable frequency excursions (from a compliance perspective) will be significantly fewer than the number of acceptable voltage excursions that would occur for model verification. Therefore, the SDT decided to allow the Generator Owner two years for verifying the model. This timeframe allows adequate time to a) realize the event has occurred while the unit was in the proper operating state, and b) to verify the model. This timeframe will also assist the Generator Owner with planning contractor, budget and schedule support if activities are outsourced.

4) A unit has to be on-line and in the proper operating state during a frequency excursion in order to capture an effective real power response for model verification. Therefore, the standard provides time for the Generator Owner to capture and record a response requiring verification, even if it takes longer than ten years to do so. This language, which is contained in the Periodicity Table, is specifically crafted so that extension of the ten year periodicity cycle will only happen if a frequency excursion does not occur with the unit on-line and in the proper operating state. Therefore, the lack of installed and operating recording equipment during a frequency excursion is not a valid excuse for obtaining a ten year timeframe extension.

5) Industry experience has shown that a unit's real power response to a system frequency excursion could be different from one event to the next. Reasons include different unit load levels, prime mover control conditions, operator control mode, and magnitude of the frequency deviation. By contrast, excitation control

system responses to system voltage excursions are much more consistent. Therefore, the main model verification requirement (R2 Part 2.1.1) calls for the turbine/governor and load control model to be “compared to” the recorded response of actual equipment whereas in standard MOD-026-1, the wording is “matches”.

6) In standard MOD-026-1 R3 there is a process where a Transmission Planner can make a written request, including evidence that the excitation control system (or plant volt/var) model response did not match an actual recorded response, to the Generator Owner which essentially requires the Generator Owner to review the model. While there is similar language in standard MOD-027-1 R3, there is the additional stipulation that the Transmission Planner must include supporting evidence of instances where model response did not match an actual recorded response. The reason for this is that the governor response is not consistent enough from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. In fact, while the fundamental requirement for verifying the model once every ten years can be satisfied by taking into account only a single frequency excursion, it is strongly recommended that model verification be performed taking into account multiple frequency excursions (if available and assuming the unit was in a proper operating state as required for model verification).

7) The activity specified in Requirement R4 is similar to draft standard MOD-026-1 Requirement, R4 which lists the evidence of compliance that the Generator Owner must maintain whenever certain activities occur that alter the equipment response; resulting in providing either revised model data or re-verifying the model. Unlike excitation control systems, there are many control parameters associated with the turbine/governor and load control system which will not impact equipment performance that is required to be replicated in the dynamic model. Thus, standard MOD-027-1 Requirement R4 is specifically crafted to only include setting changes for droop, and/or dead band, and/or load control mode. Since it is likely that many Generator Owners will rely on the expertise of consultants to make the determination of how modifications to droop, dead band, and/or load control mode translate into modified model parameter values, a time period of 180 days is proposed.

8) In MOD-026-1, the SDT is proposing a process where the Planning Coordinator can request a review of an excitation control system model for a unit not specified in the standard Applicability section. The new MOD-026-1 Requirement (R5) was added in response to industry comments. It requires the Planning Coordinator to supply technical justification that demonstrates either a) the unit affects a stability limit, or b) the simulated unit response does not match a measured unit response (most likely captured during a system disturbance event). However, this process is not being proposed for MOD-027-1. It is extremely unlikely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit. Also, as already discussed (Item 6), governor response is not consistent from one frequency excursion event to the next. Therefore, the SDT did not feel that such a Requirement in MOD-027-1 was necessary.

9) There is no need for the Transmission Planner to provide the generator MVA base when providing models for turbine/governor and load control or active power/frequency control systems. The MVA base associated with the generator model is already required to be provided per Requirement R1 of standard MOD-026. The MW base information is reflective of turbine capability and is provided as one of the turbine/governor and load control model data parameters specified. The MW base information, depending on the dynamic simulation software provider model requirements, will either be in the form of an actual MW value or a per unit MW value; with the base being the MVA value that is used in the generator steady state model.

10) The Generation Verification SDT is closely following and coordinating with the Frequency Response SDT. It is hoped that the Frequency Response SDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, though the Frequency Response SDT has discussed this concept and is investigating the use of a tool to help facilitate the identification of appropriate frequency excursions, the process is still evolving. As an interim step, the Generation Verification SDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine/governor and load control functions for the purpose of model verification and b) would be expected to occur 15 times a year or more. If by chance a process identifying frequency excursions that can be utilized in support of standard MOD-027-1 requirements is not developed by the Frequency Response SDT, then such a process will have to be proposed for future revision to standard MOD-027-1 by the Generation Verification SDT.

Compliance Elements for MOD-026-1:

The SDT added Compliance Elements to the second posting of the standard. The VRF's for Requirements R1-R6 are all designated as low risk. All of these Requirements provide for an update of dynamic modeling data for an existing unit. Violation of these requirements would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system, which is consistent with the low risk level guidelines.

The VSLs for Requirement R2 was selected using the metric of "Requirements with Parts that Contribute Equally to the Requirement". All of the items listed in Requirement R2 are required for successful model verification. The remaining VSLs were selected using the metric of "Increments for Tardiness". The Requirements cover activities that are not typical such as peer reviews and instances where there is concern that the model does not reliably reflect actual equipment performance. As such, timeliness of communications is paramount.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The Applicability section of MOD-026 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability?

   ☐ Yes

   ☐ No

   Comments:

2. The current version of the MOD-026 standard has been re-formatted so that it would be more concise and contain only reliability related requirements. Do you agree there are no omissions from the prior draft due to the re-formatting of the standard?

   ☐ Yes

   ☐ No

   Comments:

3. The SDT discussed if MOD-026-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR.

   Do you agree with the proposal to not include the verification of synchronous condensers in MOD-026-1?

   ☐ Yes

   ☐ No

   Comments:

4. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain.

   ☐ Yes

   ☐ No

   Comments:

Unofficial Comment Form for Generator Verification (Project 2007-09)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the Second Posting of PRC-024-1 Generator Performance During Voltage and Frequency Excursions (Project 2007-09). The electronic comment form must be completed by **August 1, 2011.**

Project 2007-09 Generator Verification

If you have questions please contact Stephen Crutchfield at Stephen.Crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).

- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024-1 — Verification of Generator Gross and Net Real Power Capability.

- MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability.

And four draft standards developed by the Phase III & IV SDT that were fielded tested by four Regions from mid 2006 through mid 2007.

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions

- MOD-027-1 — Verification of Generator Unit Frequency Response

The second posting of standard PRC-024-1 Generator Performance During Voltage and Frequency Excursions was developed with consideration of industry response to questions that were posed as part of the Comment Form accompanying the first posting.

One of the major issues that the SDT presented to industry during the first posting was the consideration of a relay setting standard versus a performance standard. Based on comments from the first posting, the SDT has again carefully reviewed the original SAR and FERC Order 693, and has modified the standard to reflect requirements for relay settings and performance. For existing generators, the requirements for frequency and voltage are centered around relay settings and on communicating to the planning entities the anticipated performance of a generator during a voltage or frequency excursion. The FERC Order stated that generators should either ride through the events, or be modeled as tripping. For new generators, the SDT has modified the standard to include performance requirements.

After considering comments the SDT has kept the applicability to Generator Owners as described in the NERC Compliance Registry Criteria.

The SDT also considered including synchronous condensers as applicable facilities for this standard. We determined that it is not necessary to include synchronous condensers because frequency transients within the scope of this standard are not a serious concern for synchronous condensers, and most synchronous condensers do not have the auxiliary systems that would cause a condenser to trip under the voltage transients defined in this standard.

The requirements for frequency relay settings were based upon reviews of manufacturers' information, existing regional requirements and coordination with the Under Frequency Load Shedding SDT.

The drafting team intends Requirement R5 to address parameters that the generating unit(s) or plant/facility ride through during Frequency/Voltage Excursions. The SDT does not intend the standard to address dynamic instability, transient instability or any form of loss of synchronism.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. There are two new terms proposed in this standard. "Frequency Excursion" and "Voltage Excursion". The former defined as an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz. The latter defined as an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage. Do you agree with these new terms and their definitions? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. Requirements R1 and R2 detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Does the current draft of these two requirements, including footnote 1, clarify that a Generator Owner is not required to have protective relaying installed or set for these functions? If you do not believe the requirement is clear, please provide alternative language to clarify the intent.

   ☐ Yes

   ☐ No

   Comments:

3. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language.

   ☐ Yes

   ☐ No

   Comments:

4. Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer.

   Please provide along with your comment, what you believe the timeframe is needed to implement this requirement.

   ☐ Yes

   ☐ No

   Comments:

5. The voltage ride-through Tables HVRT and LVRT Duration in Attachment 2, specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Do you agree with this time duration value? If not, please provide an alternative value and supporting information in the comments.

   ☐ Yes

   ☐ No

   Comments:

6. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

   ☐ Yes

   ☐ No

   Comments:

Standards Announcement

Project 2007-09 Generator Verification
Ballot Pool Windows Open: June 15 – July 15, 2011
Formal Comment Period Open (Two Standards): June 15 – August 1, 2011
Formal Comment Period Open (Three Standards): June 15 – July 15, 2011

Now available at: http://www.nerc.com/filez/standards/http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

The Generator Verification standard drafting team has posted five standards and their associated implementation plans for a formal comment period. Please read the following announcement carefully, because although the five standards are being posted together they are at different stages in the standards process and in order to facilitate moving forward those standards that reach consensus, the standards are being processed independently.

1. MOD-026-1 and PRC-024-1 Formal Comment Period and Ballot Pool Formation

Two of the standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Frequency and Voltage Protective Relay Settings, are posted for a 45-day formal comment period through August 1, 2011. A ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-026-1 and PRC-024-1 beginning on July 22, 2011. Please note that **separate ballot pools are being formed for each standard and non-binding poll**, and the window to join the ballot pool for each standard and each non-binding poll is open through July 15, 2011.

Ballot Pools Open through 8 a.m. EST on July 15, 2011 for MOD-026-1 and PRC-024-1 Ballots and Non-binding Polls

The Standards Committee has authorized posting these standards and their associated implementation plans for a 45-day formal comment period with an initial ballot and concurrent non-binding poll conducted during the last 10 days of that comment period. A separate ballot pool is being formed for each standard and for each non-binding poll in order to allow Registered Ballot Body members to selectively join those ballot pools in which they have an interest. To register an opinion in the non-binding poll for either standard, you must join the ballot poll for that non-binding poll. Each of the four ballot pools will be open through 8 a.m. EST on July 15, 2011.

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- PRC-024-1 ballot bp-2007-09_PRC-024-1_in@nerc.com
- PRC-024-1 non-binding poll bp-2007-09_PRC-024-1_NB_in@nerc.com

Instructions for Commenting

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2. MOD-025-2, MOD-027-1, and PRC-019-1 Formal Comment Period

Three additional standards have been posted for a 30-day formal comment period:

- MOD-025-2 – Verification of Generator Gross and Net Reactive Power Capability
- MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- PRC-019-1 – Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

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Next Steps

Initial ballots of MOD-026-1 and PRC-024-1, and concurrent non-binding polls of the associated VRFs and VSLs, will begin on July 22, 2011 and end at 8 p.m. Eastern on Monday, August 1, 2011. Following the formal comment period for MOD-025-2, MOD-027-1, and PRC-019-1, the drafting team will consider all comments and determine whether to make changes to the standards, implementation plans, or associated VRFs and VSLs.

Background

The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

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- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

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Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

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Instructions for Commenting

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- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Additional details are available on the project web page at http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Revised: Standards Announcement

Project 2007-09 Generator Verification
Results of Two Initial Ballots and Non-binding Polls

Update now available at: https://standards.nerc.net/Ballots.aspx

Initial ballots of two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Frequency and Voltage Protective Relay Settings, and concurrent, non-binding polls of the associated VRFs and VSLs concluded on Monday, August 1, 2011.

Revised Ballot Results for MOD-026-1 and PRC-024-1

Updated voting statistics for each standard are listed in the table below, and the Ballot Results Web page provides a link to the detailed results.

Standard	Ballot Results	Non-binding Poll Results
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions	Quorum: 90.25% Approval: 46.53%	88.75% of those who registered to participate provided an opinion or abstention; 56% of those who provided an opinion indicated support for the VRFs and VSLs
PRC-024-1– Generator Performance During Frequency and Voltage Excursions	Quorum: 90.82% Approval: 18.23%	88.35% of those who registered to participate provided an opinion or abstention; 20.79% of those who provided an opinion indicated support for the VRFs and VSLs

Reason for Revisions

We announced the ballot and non-binding poll results on August 5, 2011 and became aware yesterday that one company submitted a vote via e-mail that was not received by the process administrator due to a problem with NERC’s IT systems. The NERC IT department has been made aware of the situation and is researching the cause. We will provide stakeholders with an alternative method of submitting e-mail ballot which will be highlighted in any future ballot announcement. It is important to note that all votes submitted through NERC’s electronic balloting application have been received.

The only time votes are accepted via e-mail is for an entity that has registered someone in a ballot pool who is not in that role. When the ballot pool member is no longer available to cast a ballot for the entity, we make every effort to allow the entity to continue to participate in the ballot pool by manually entering the vote for the person designated as his/her replacement. Our software, in its current format does not update ballot pools when an entity's Registered Ballot Body member changes, which forces us to enter these ballots through the manual process.

We are committed to maintaining an accurate record of this ballot. If you sent your votes via e-mail, please review the attached ballot results to ensure that your votes are included (or view the project page for the updated posted results: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html).

If you find that your entity's votes were not posted, please call Monica Benson at 404-446-2573. You will need to send verification of any e-mail vote showing that the ballot was sent before the close of the ballot window, which will be forwarded to our IT department for review.

Thank you for your patience and understanding as we make any necessary voting result updates to ensure that accurate voting records are posted.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-09 Generator Verification
Results of Two Initial Ballots and Non-binding Polls

Now available at: https://standards.nerc.net/Ballots.aspx

Initial ballots of two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Frequency and Voltage Protective Relay Settings, and concurrent, nonbinding polls of the associated VRFs and VSLs concluded on Monday, August 1, 2011.

Ballot Results for MOD-026-1 and PRC-024-1

Initial ballots of MOD-026-1 – Verification of Models and Data for Generator Excitation Control System Functions, and PRC-024-1– Generator Performance During Frequency and Voltage Excursions and non-binding polls of the VRFs and VSLs associated with each standard concluded on Monday, August 1, 2011.

Voting statistics for each standard are listed in the table below, and the Ballot Results Web page provides a link to the detailed results.

Standard	Ballot Results	Non-binding Poll Results
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions	Quorum: 89.94% Approval: 47.24 %	88.75% of those who registered to participate provided an opinion or abstention; 56% of those who provided an opinion indicated support for the VRFs and VSLs
PRC-024-1– Generator Performance During Frequency and Voltage Excursions	Quorum: 90.51% Approval: 18.50%	88.35% of those who registered to participate provided an opinion or abstention; 20.79% of those who provided an opinion indicated support for the VRFs and VSLs

Next Steps

The drafting team will consider all comments received (those submitted with a comment form, and make revisions to the standards. If substantive changes are made to the standards, the team will submit its documents for a quality review.

Background

The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2 and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Additional details are available on the project web page at http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

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North American Electric Reliability Corporation
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Princeton, NJ 08540
609.452.8060 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2007-09 MOD-026-1 Initial Ballot_June 2011_in
Ballot Period:	7/22/2011 - 8/1/2011
Ballot Type:	Initial
Total # Votes:	287
Total Ballot Pool:	318
Quorum:	**90.25 % The Quorum has been reached**
Weighted Segment Vote:	46.53 %
Ballot Results:	**The standard will proceed to a successive ballot.**

Summary of Ballot Results

			Affirmative		Negative		Abstain	
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**# Votes**	**No Vote**
1 - Segment 1.	85	1	45	0.643	25	0.357	6	9
2 - Segment 2.	6	0.4	0	0	4	0.4	1	1
3 - Segment 3.	68	1	25	0.439	32	0.561	8	3
4 - Segment 4.	25	1	9	0.45	11	0.55	2	3
5 - Segment 5.	75	1	32	0.5	32	0.5	2	9
6 - Segment 6.	42	1	17	0.486	18	0.514	2	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.4	2	0.2	2	0.2	3	1
9 - Segment 9.	2	0.2	0	0	2	0.2	0	0
10 - Segment 10.	7	0.7	4	0.4	3	0.3	0	0
Totals	**318**	**6.7**	**134**	**3.118**	**129**	**3.582**	**24**	**31**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden	Affirmative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		

1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	Southwest Power Pool	Charles H Yeung		
3	AEP	Michael E DeLoach	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	

3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	John Apperson	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	View
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	View
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	View
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Negative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	

5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Gainesville Regional Utilities	Karen C Alford	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	View
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tenaska, Inc.	Scott M Helyer	Negative	View
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Negative	View

6	Dominion Resources, Inc.	Louis S. Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Negative	View
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Negative	View
8		Merle Ashton		
8		Edward C Stein	Affirmative	
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Negative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	View
10	Texas Reliability Entity	Larry D Grimm	Negative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2007-09 PRC-024-1 Initial Ballot June 2011_in
Ballot Period:	7/22/2011 - 8/1/2011
Ballot Type:	Initial
Total # Votes:	287
Total Ballot Pool:	316
Quorum:	**90.82 % The Quorum has been reached**
Weighted Segment Vote:	18.23 %
Ballot Results:	**The standard will proceed to a successive ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	82	1	16	0.232	53	0.768	5	8
2 - Segment 2.	6	0.4	0	0	4	0.4	1	1
3 - Segment 3.	68	1	8	0.131	53	0.869	4	3
4 - Segment 4.	25	1	3	0.158	16	0.842	3	3
5 - Segment 5.	76	1	10	0.154	55	0.846	2	9
6 - Segment 6.	42	1	3	0.083	33	0.917	2	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	3	0.3	3	0.3	1	1
9 - Segment 9.	2	0.2	0	0	2	0.2	0	0
10 - Segment 10.	7	0.7	2	0.2	5	0.5	0	0
Totals	**316**	**6.9**	**45**	**1.258**	**224**	**5.642**	**18**	**29**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Negative	View
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Negative	View
1	Basin Electric Power Cooperative	David Rudolph	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le	Negative	View
1	Lower Colorado River Authority	Martyn Turner	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Negative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Negative	
1	Northeast Utilities	David Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	John T Walker	Negative	View
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Negative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Negative	View

1	South California Edison Company	Steven Mavis	Negative	View
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	Southwest Power Pool	Charles H Yeung		
3	AEP	Michael E DeLoach	Negative	
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda Jacobson	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Negative	View
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Negative	View
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Dominion Resources Services	Michael F. Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	View
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	View
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	View

3	PacifiCorp	John Apperson	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada	Negative	View
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	View
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	View
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Negative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	View
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	
5	Avista Corp.	Edward F. Groce	Negative	View
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Negative	View
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Negative	View
5	Chelan County Public Utility District #1	John Yale	Negative	View
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul Cummings	Negative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	View
5	City of Tallahassee	Brian Horton	Negative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	View
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View

5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Gainesville Regional Utilities	Karen C Alford	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Negative	View
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Roland Thiel	Negative	View
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	View
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	View
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	View
5	Salt River Project	Glen Reeves	Negative	View
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	View
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tenaska, Inc.	Scott M Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Westar Energy	Bo Jones	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Negative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Negative	View
6	Dominion Resources, Inc.	Louis S. Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	

6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Negative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Scott L Smith	Negative	View
6	Platte River Power Authority	Carol Ballantine	Negative	View
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	View
6	Salt River Project	Steven J Hulet	Negative	View
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Negative	View
6	South California Edison Company	Lujuanna Medina	Negative	View
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Affirmative	
8		Roger C Zaklukiewicz	Negative	View
8		Merle Ashton		
8		Edward C Stein	Affirmative	
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
10	Midwest Reliability Organization	James D Burley	Negative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Negative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Negative	View
10	Texas Reliability Entity	Larry D Grimm	Negative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	View

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Non-binding Poll Name:	Project 2007-09 MOD-026-1 Non-Binding Poll
Poll Period:	7/22/2011 - 8/1/2011
Total # Opinions:	198
Total Ballot Pool:	311
Summary Results:	88.75% of those who registered to participate provided an opinion; 56% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	View
1	CenterPoint Energy Houston Electric	Dale Bodden	Abstain	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	

1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

1	Los Angeles Department of Water & Power	Ly M Le	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren	Negative	View

2	Midwest ISO, Inc.	Marie Knox		
2	Southwest Power Pool	Charles H Yeung		
3	AEP	Michael E DeLoach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View

3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Negative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Don Horsley	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	

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3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	

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4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	

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5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View

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5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Gainesville Regional Utilities	Karen C Alford	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	

5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Abstain	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	Arizona Public Service Co.	Justin Thompson		

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6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	

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6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
8		Roger C Zaklukiewicz	Negative	
8		Edward C Stein	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating	Guy V. Zito	Affirmative	

	Council, Inc.			
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Texas Reliability Entity	Larry D Grimm	Negative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	View

Ballot Results	
Non-binding Poll Name:	Project 2007-09 PRC-024-1 Non-binding Poll
Poll Period:	7/22/2011 - 8/1/2011
Total # Opinions:	202
Total Ballot Pool:	309
Summary Results:	88.35% of those who registered to participate provided an opinion; 20.79% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Negative	View
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Negative	
1	Basin Electric Power Cooperative	David Rudolph	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View

1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Abstain	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	

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1	Los Angeles Department of Water & Power	Ly M Le	Negative	View
1	Lower Colorado River Authority	Martyn Turner	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Negative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff	Negative	
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	
1	Portland General Electric Co.	John T Walker	Negative	View
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts	Negative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View

1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Negative	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Negative	View
1	South California Edison Company	Steven Mavis	Negative	View
1	Southern Company Services, Inc.	Robert Schaffeld	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	Midwest ISO, Inc.	Marie Knox		
2	Southwest Power Pool	Charles H Yeung		

3	AEP	Michael E DeLoach	Negative	
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda Jacobson	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Negative	View
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary	Negative	View
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	

3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Negative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Don Horsley	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	View
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	View

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3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada	Negative	View
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	View
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	

4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Negative	
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Negative	View
5	Avista Corp.	Edward F. Groce	Negative	View
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	View

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RELIABILITY CORPORATION

5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Negative	View
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul Cummings	Negative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	View
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	View
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View

5	Gainesville Regional Utilities	Karen C Alford	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Roland Thiel	Negative	View

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	Glen Reeves	Negative	View
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Westar Energy	Bo Jones	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	Arizona Public Service Co.	Justin Thompson		

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RELIABILITY CORPORATION

6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	City of Redding	Marvin Briggs	Negative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Scott L Smith	Abstain	

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6	Platte River Power Authority	Carol Ballantine	Negative	View
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	
6	Salt River Project	Steven J Hulet	Negative	View
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Negative	View
6	South California Edison Company	Lujuanna Medina	Negative	View
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
8		Roger C Zaklukiewicz	Negative	
8		Edward C Stein	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
10	Midwest Reliability Organization	James D Burley	Negative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating	Guy V. Zito	Affirmative	

	Council, Inc.			
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Texas Reliability Entity	Larry D Grimm	Affirmative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	View

Individual or group. (67 Responses)
Name (40 Responses)
Organization (40 Responses)
Group Name (27 Responses)
Lead Contact (27 Responses)
Question 1 (53 Responses)
Question 1 Comments (67 Responses)
Question 2 (45 Responses)
Question 2 Comments (67 Responses)
Question 3 (51 Responses)
Question 3 Comments (67 Responses)
Question 4 (57 Responses)
Question 4 Comments (67 Responses)
Question 1 (56 Responses)
Question1 Comments (67 Responses)
Question 2 (56 Responses)
Question 2 Comments (67 Responses)
Question 3 (57 Responses)
Question 3 Comments (67 Responses)
Question 4 (48 Responses)
Question 4 Comments (67 Responses)
Question 5 (47 Responses)
Question 5 Comments (67 Responses)
Question 6 (59 Responses)
Question 6 Comments (67 Responses)

Group
Arizona Public Service Company
Janet Smith
No
Yes
Yes
No
Yes
Yes
No
AZPS believes this question applies to R5. In any event, this requirement does not add anything to the reliable modeling since most GO(s) will be making a guess, and that does not make the simulation any more accurate. Additionally, the requirement for providing this information within 30 days is unreasonable. It should be at least 90 days. There is no reliability reason for requiring this data within 30 days. These are long range planning studies and modeling data is usually submitted on the annual basis.
No
AZPS believes this question applies to R6. There should be an implementation period for the requirement for new units to allow the plants which have been ordered already to not to have to be redesigned.
Yes

The measurement M6 for the new plant is not clear. One does not know how long a time it would take to get a significant event. M6 should be written such that if a unit did not trip for a system event, it will be considered compliant.
Group
Pepco Holdings Incand Affiliates
David Thorne
No
Suggest replacing the term “scheduled voltage” with “nominal operating voltage”. Voltage schedules may change over time, whereas “nominal” or “rated” voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, “rated” or “nominal” voltage.
No
Footnote 1 does make it clear that the Generator Owner is not required to have frequency or voltage protective relaying. However, in the current draft, reference to footnote 1 appears to have been inadvertently omitted following the phrase “voltage protective relaying” in R2.
No
Believe this question is referring to Requirement R5 not R4 as stated in the question. Not sure how useful the R 5.2 probability assessment would be, therefore suggest eliminating that requirement. R 5.1 coupled with the basis requirement in R 5.3 would appear sufficient to quantitatively assess the performance during voltage and frequency excursions. Also, see responses to question #6.
Yes
Believe this question is referring to Requirement R6 not R5 as stated in the question. Yes, it is possible to design a new facility to operate within the requirements identified in this standard. However, it may require specification of equipment with higher than normal overvoltage capabilities. Also, significant analyses would have to be conducted on the behavior of plant control systems (exciter controls, boiler controls, etc.), as well as equipment connected to auxiliary busses (including low voltage motor contactors) to ensure that all systems are designed with appropriate ride-through capabilities. However, it is unclear how this standard would apply to the ride through capability of units connected to the BES, but whose source of auxiliary station service power is from a non-BES interconnection. Would the units also have to ride through expected voltage excursions at the point of interconnection with the station service transformer even if the station service transformer was not fed directly from the BES?
Yes
1) The applicability section from the previous draft of this standard should be re-inserted. Although the SDT chose to remove that section since the standard is intended to apply to all generation facilities that meet Compliance Registry Criteria, adding the specific generation criteria for which this standard applies within the body of the standard provides much more clarity than having to refer to a second document to define applicability. In addition, inserting the full applicability criteria would be consistent with the way Applicable Facilities are identified in Section 4.2 of PRC-019-1. 2) Requirement R 2.1.1 should be re-worded as follows: “For three-phase faults with Normal Clearing on transmission system facilities (lines, busses, transformers, etc.) adjacent to the point of interconnection, set voltage relays to ride through expected fault clearing times, not to exceed 9 cycles.” The use of the term “zone 1 faults” implies that zone 1 relaying schemes are always employed on the transmission system, which may not be the case. Pilot schemes, overcurrent schemes, differential schemes, etc. may be used instead. Also, the unit should stay connected if a fault were to occur on an adjacent bus or transformer rather than just on lines. Also, use of the term “Zone 1 fault” in Requirement R5 needs to be similarly addressed. 3) Requirement R 2.1.1 should also address ride through capability for TPL Category C contingencies (i.e. single line to ground faults with a stuck breaker, or other cause for delayed clearing) since generation units are expected to remain on

line during these contingencies as well. Granted, a three phase fault would be the most severe, however a single line to ground fault with delayed clearing times could also cause unwanted unit tripping, leading to a violation of Reliability Criteria. 4) The SDT in their response to comments on Draft #1 of this standard stated that “Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings.” This is fine for evaluating the response to three phase faults, or other balanced system disturbances. However, if it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with three phase faults, then it is equally as important to have them remain on-line for single line to ground faults, which are much more common. During a phase to ground fault at the point of interconnection the faulted phase voltage collapses to zero but the unfaulted phase to ground voltages could rise as high as 80% of the line to line voltage for an effectively grounded system (with a coefficient of grounding = 80%). This is well in excess of the 1.2 p.u. requirement shown in Attachment 2. Generator voltage protection relays respond to actual phase voltages not just positive sequence voltages. As such, for the unit to ride through phase to ground faults at the point of interconnection then the short time 1.2 p.u. overvoltage threshold needs to be raised above 0.8 x 1.73 = 1.38 p.u. 5) The revised language in R3 referring to “the equipment limitation expires coincident with ….” is unclear and confusing. How can the “limitation” expire merely by the generating unit continuous capacity rating being increased > 10%. The Draft #1 version of this standard uses the phrase “the Generator Owner is granted an exception for that unit meeting the portion of R1 or R2 for that limitation once it provides documentation of the equipment limitation(s)…” “This exception for the equipment limitation shall expire coincident with…” The use of the term “exception, or exemption”, makes more sense and is more in line with the intent of this section. As such, the original language from Requirement R5 from Draft #1 should be re-instated. 6) Typically unit connected generator protection packages, which include frequency and voltage protective elements, are supplied by voltage transformers connected on the terminals of the generator rather than on the high side of the generator step-up (GSU) transformer. For frequency elements, the frequency at the terminals of the generator is the same as on the high side of the GSU transformer. So comparison of frequency protective element set points can be made directly with Attachment 1. However, this is not true for voltage. The generator terminal voltage could be higher, or lower, than the system voltage on the high side of the GSU transformer depending on the voltage drop across the transformer, which varies depending on the generator real power output and whether the generator is supplying or absorbing reactive power. Since this standard requires the generation to remain connected for specific voltage criteria as measured at the point of interconnection, but the voltage sensing protection is connected to the generator terminals, some technical guidance (with specific examples) must be provided to allow the Generator Owner to translate these voltage criteria to the voltages seen by the protective relays on the terminals of the generator. Otherwise an incorrect evaluation may result. It is recommended that a Technical Reference Document similar to the “Power Plant and Transmission System Protection Coordination” document developed by the NERC System Protection and Control Subcommittee be produced, or the above mentioned document revised, to provide illustrative examples of how to apply the Attachment 2 POI voltage criteria to voltage sensing protective elements connected to the terminals of the generator. 7) Comments on “Voltage Ride-Through Curve Clarifications” which appears on the last page of the standard: Item#1 - Suggest replacing the term “scheduled operating voltage” with “nominal operating voltage”. Voltage schedules may change over time, whereas “nominal” or “rated” voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, “rated” or “nominal” voltage. Item #2 - Suggest eliminating item 2. The ride-through curve is to ensure the unit remains on line for voltage excursions up to the limits defined by Attachment 2, regardless of the cause of the voltage excursion. Item #3 – The use of the term “cumulative voltage duration” is confusing since Attachment 2 is made up of a series of discrete allowable voltage magnitudes and durations. Also, the language only mentions voltage protective relaying and not other non-protective equipment, which could cause the unit to trip. Suggest re-wording as follows: “The generator shall remain connected (i.e., “ride-through”) voltage excursions caused by disturbances on the transmission system, when the voltage at the point of interconnection with the BES remains within the boundaries of these curves.” Item #5 d – suggest removing the term “scheduled”, making it read “d. Voltage is measured at the point of interconnection”
Group
Northeast Power Coordinating Council

Guy Zito
No
No
Any requirement that requires reporting based on a deviation greater than a specified threshold, that threshold should be included in that requirement, refer to R5 as an example. With those stipulations, those new terms are not needed.
Yes
No
The reference to “R4” in this question should be R5.
No
The refererence to “R5” in this question should be R6.
Yes
Yes
In R3, the SDT should review that generators are not required to provide a remedial plan for an equipment limitation. For the SDT’s consideration is the work done by and for the NPCC UFLS RSDT. It was recommended to retain the more conservative NPCC Frequency Capability Curve for setting generator protection as opposed to the proposed Frequency Capability Curve in PRC-024-1 for the following reasons: 1. Some portions of the NPCC Region have additional stages of UFLS set at lower frequency thresholds below 58 Hz. Adopting the curve in Attachment 1 may impact the effectiveness of the UFLS program from arresting frequency decline in these depressed frequency ranges. 2. As the numbers of distributed generators connected to the system increase, it is expected that overall generator frequency response is expected to be reduced. The distributed generation may also not need to comply with the generation trip thresholds as they may not meet the existing thresholds applicable to Generator Owners in NERC’s Statement of Compliance Registry Criteria. Adopting the proposed PRC-024-1 curve would jeopardize the survival of islands that may contain increasingly larger portions of distributed generation should the frequency decline below 58 Hz. 3. Adopting the proposed PRC-024-1 curve reduces the probability that the UFLS program will successfully arrest declining frequency for system conditions that are not addressed in NPCC’s 2006 UFLS Assessment. 4. Adopting the proposed PRC-024-1 curve would decrease the ability of an island to survive more severe conditions than those considered in the UFLS design (for example, islands with a generation deficiency greater than 25 percent).
Group
Westar Energy
Bo Jones
No
Yes
Yes
Yes
The applicability in this standard (≥100 MVA) is consistent with the applicability in MOD-027-1. However, the applicability in this standard is not consistent with MOD-025-2 and PRC-019-1. We propose that the SDT revise the applicability to be consistent between all of the standards included in this project.
No

We agree with the frequency excursion defined as +/-0.5Hz. We agree that ±5% is appropriate for normal operating conditions. However, this does not address contingencies or timeframes. The SPP regional criteria allows for a +5% to -10% change from nominal voltage on load serving buses under single contingency conditions. The Voltage Ride-Through Time Duration Curve in Attachment 2 does not appear to correspond with the proposed definition. The Voltage Ride-Through Time Duration Curve in Attachment 2 indicates that at 600 seconds, one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria states that we can operate at a +5% to -10% of nominal voltage on load serving buses during a contingency. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of this definition. We propose that the SDT consider defining continuous. We are unclear if continuous means from zero to infinite.
Yes
No
This question better addresses R5 rather than R4. We propose that the SDT team consider revising the 30 day requirement to provide documentation of the equipment limitation to 90 days in R5. We recommend that 90 days is a more appropriate timeframe for supplying this documentation.
Yes
No
We suggest that the SDT provide the technical justification for this time duration. We do not agree with the time duration of up to 600 seconds. This time duration appears to be significantly long for voltage recovery. From a planning perspective, 15 cycles or 0.25 seconds is standard for voltage recovery. Holding 0.9 from 3 seconds to 600 seconds could be difficult if there is full load on the unit. There may not be enough bandwidth before a loss of field relay occurs. If enough current is provided to the field, it will cause the relay to trip instantaneously. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of the attachment.
No
Individual
Edward Cambridge
APS
being intentionally left blank (no answer to be provided)
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Individual
Edward Cambridge
APS
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Individual
Michael Goggin
American Wind Energy Association
No
Yes
Yes
No
Yes
Yes
Yes
Yes
New reliability standards should be accompanied by grandfathering provisions for existing generators and an implementation grace period of sufficient length to ensure that manufacturers have enough time to engineer their generators to comply with the standard and that generators for which purchase orders are already in the pipeline will not need to be re-designed. The grandfathering provisions and implementation grace period schedule that were included in FERC Order 661A should be sufficient to achieve those goals if they are incorporated into this standard.
Yes
No
Individual
Samuel Reed
Tri-State Generation and Transmission, Inc.
No
Yes
Yes
No
No
We don't think exceedance is a word. Suggest changing it to "operating outside of a continuous range of 60+/- 0.5 Hz". We don't agree with using the phrase "scheduled voltage" as is staed in the question, but the actual standard uses "rated voltage" with which we do agree.
Yes
Yes

Yes
Yes
Yes
The proposed WECC-0065 does not comply with the generator overfrequency curve.
Individual
Bob Casey
Georgia Transmission Corporation
Yes
Does Applicability 4.2.4 "Any technically justified unit requested by the Planning Coordinator" override the greater than 5% capacity factor over the last three calendar years statement in 4.2? It should in the case of units needed to prevent FIDVR problems and other peak hour considerations.
Yes
Yes
Yes
Should references to Planning Coordinator be changed to Transmission Planner (4.2.4 and R5)? Or, should Planning Coordinator be added as a functional entity? Have software manufacturers agreed to provide their models as described in R1?
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
Yes
Yes
THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
No
Yes
Yes
Yes
According to the standard this language is R5
Yes
According to the standard this language is R6
Yes

No
Individual
Hamish Wong
Wisconsin Public Service Corp
No
Yes
No
Synchronous condensers are installed at where they are specifically for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.
Yes
We have a number of questions and concerns as follows: • While the Standard uses the word “verified” and “verification” loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? • We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for excitation control was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Individual
Joe Petaski
Manitoba Hydro
No
Yes
No
Manitoba Hydro disagrees with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs,

STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators.
Yes
1)For Section 4.2 Facilities, the section should refer to ‘BES Generating Units and Facilities’ instead of restating components of the proposed BES definition. 2)Attachment 1 is not clear. Specifically, -the “Condition” in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be ‘verified’ and serve as evidence for multiple units meeting the conditions listed. -the wording for the allowance of a representative unit to be verified and submitted as evidence for identical units is not clear. -the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected ‘with the verified model’ which is incorrect. -We suggest the following. A statement that precedes the Attachment 1 table should be added that reads ‘For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ’ Row 1 should then be Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is ≤ 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.
Yes
Yes
Yes
No
While the requirement is technically achievable, justification should be provided by the drafting team for the curves in Attachments 1 and 2. It is not clear why the ‘no trip zone’ limits are set where they are.
Yes
Yes
Please provide justification for the curves provided in Attachments 1 and 2.
Group
ACES Power Members
Jason Marshall
No
Yes
Yes
Yes
This standard is highly administrative and full of compliance risks not associated with reliability. The purpose of the standard is to ensure that the GO provides an accurate model to the TP and ultimately to the PC. The requirements unnecessarily document the give and take that must occur between the GO and TP to produce a good model. R2, which essentially requires the GO to provide a good model,

is the only requirement needed. Everything else is just documentation related and unnecessary.
Yes
Yes
No
Requirement R4 references inquiries regarding equipment limitations that have been identified in R3. This particular question should apply to R5 instead. If applied to R5, the approach in theory seems reasonable.
Yes
R3 is an unnecessary requirement. Enforcement of R1 and R2 already create a de facto requirement to document limitations. Thus, R3 creates an opportunity for double jeopardy.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
Yes
The implementation plan call for a certain % of applicable plants to be in compliance over a certain number of years. Since plants may be registered individually, it is unclear what the term applicable plants is referring to in the implementation phase. Oncor takes the position that the reporting requirements for the Generator Owner as specified in R1, R2,R3,R4,R5 & R6 should be to the Planning Authority and not the Transmission Planner in the ERCOT Region. This would align with the current protocols, operating guide and planning guide that require the ERCOT ISO to be the primary interface with Generation Resources. The ERCOT ISO is registered as the Planning Authority. One option would be a regional variance that would point to the Planning Authority or Planning Coordinator in lieu of the Transmission Planner.
Yes
Yes
No
It is unclear as to what constitutes an estimate of performance.
Yes
Yes
No
Individual
John Bee on behalf of Exelon
Exelon
No

No
Differences between draft 1 and draft 2 of MOD-026 appear to be significant. Without reading through all 134 pages of comments and how the SDT addressed those comments it is too difficult to tell how the requirements were evaluated and if omissions were intentional or not. Suggest that the SDT prepare either a mapping document or a "redline to previous version" to illustrate changes and disposition of such changes to ensure there are no omissions from the prior draft.
Yes
Yes
Requirement R2 Exelon is in agreement that the Generator Owner (GO) should provide the generator excitation control system and plant volt/var control model and any necessary input data; however, the Transmission Planner (TP) should be the entity that is responsible for the model verification. Transmission Planning organizations have the expertise to implement and test the models in software, while the GOs have the necessary access to the equipment in the field. Most GOs do not have the software and the necessary personnel with the expertise to perform the modeling and model testing required by this draft Standard. Typically, TPs currently have existing software programs to run the excitation system models. The overall quality of the verification would be best served by having the TP that has knowledge in the model performance verse the GOs that do not have the current expertise in model performance or dynamic system response evaluations. Exelon also believes that the Standard should specifically define the acceptance criteria. If the acceptance criteria are left up to the GOs, then the TOs may have to deal with multiple acceptance criteria within a single Region. At the same time, a single GO may have to work with multiple TOs, which will lead to inconsistency if definition of the acceptance criteria is left up to the TO. Requirement 2.1.1 The Standard needs to provide specific guidance as to what criteria a voltage excursion from either a staged test or a measured system disturbance should be in regards to performing the verification. In addition, the SDT should provide specific examples of what types of staged tests would be considered acceptable. It is difficult to comment on the potential impact to the generating units (especially a nuclear generating unit) without knowing the criteria.
No
The definitions provided for Frequency Excursion and Voltage Excursion are not consistently applied throughout the Standard. Several of the uses of the term “excursion” (R1.2, R5.1, R5.2, R6, etc…) refer to the graphs in Attachments 1 and 2, which are based on time characteristics. Exelon agrees that 60 HZ +/- 0.5 Hz is reflective of a (normal) continuous operating band; however, the voltage +/- 5% is not necessarily a (normal) continuous operating band of "scheduled voltage". The "scheduled voltage" should be consistent with VAR-001 and VAR-002. VAR-001 Requirement R.4 states: "Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator." VAR-002 Requirement R.2 states: "[Unless exempted by the Transmission Operator] each Generator Operator shall maintain the generator voltage or Reactive Power output … as directed by the Transmission Operator." Suggest that the definition for Voltage Excursion is revised to state "an exceedance of system voltage beyond (i.e., outside) nominal operating band as determined by the Transmission Operator"
No
Footnote 1 should be added to the Applicability section of the Standard. Suggest that the Applicability section be revised to state "GO shall set applicable protective relaying so as not to impact R1.1, R1.2, R1.3, R1.5, unless exempted by a non-protection system equipment limitation per the exclusion criteria in Requirement R3."
No
This question refers to Requirement R5 not Requirement R4. The "ride through" criteria should not extend beyond currently used critical clearing time (2nd zone of protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether nuclear units can survive anything beyond this. Plants with auxiliary power systems fed directly from the nuclear switchyard would be even more questionable as the transient is not shielded by the generator bus.
Yes

Most nuclear units will not be able to meet the time duration of "up to 600 seconds" unless they have an installed Load Tap Changer (LTC). This is due to the NRC required Degraded Voltage relay protection. The purpose of degraded voltage relaying is to protect emergency buses that feed equipment necessary for safe nuclear plant shutdown during an emergency or transient.
Yes
Applicability section and Requirements R.1 and R.2 Most nuclear power plants will not meet the requirements for frequency due to NRC required protection for Reactor Coolant Pumps and Reactor Protection System Motor Generator sets. In addition, most nuclear power plants will not meet the voltage requirements due to NRC required degraded voltage protection. Although a provision for exemption is permitted in R.3, Exelon requests that the SDT communicate with the NRC and with the FERC to ensure a conflict of dual regulation is not imposed on a nuclear generating unit without the necessary evaluation. Requirement R.3 second bullet The equipment limitation expiration should not be dependent on a capacity increase of the generating unit. An equipment limitation may be the result of NRC regulations and not the generating unit capacity.
Individual
Eric J Anderson
New York Power Authority
Yes
Yes
Yes
No
Yes
Yes
Yes
Yes
It is achieveable but signficant analyses must be performed. Undervoltage relay settings must be coordinated with the plant components most sensitive to system wide voltage excursions, particularly voltage drops. In some facilities, a POI voltage dip to 0.95pu would translate to a much larger drop within the local facility such that facility auxiliaries would start tripping due to the lower volatges on the facilities internal buses. The result is that even thogh the HV bus undervolatge relay is set to allow 0.95pu on the system the facility internal distribution may not be able to cope with voltage at that low a level. Nuclear power plants are particularly susceptible to low voltage conditions as unplanned tripping of a nuclear unit is to be avoided as much as possible. Nuclear units are also susceptible to overfrequency excursions as overfrequency causes motors within the plant to run at higher speeds. Nuclear reactor coolant pumps have overspeed limits due to core internals vibration limits that must be analyzed and coordiated with system overfrequency relay settings. These analyses typically take six to twelve months to complete and validate so a 12 to 18 month timeframe should be sufficient to implement the requirement.
Yes
No
Individual
Dan Roethemeyer
Dynegy Inc.

No
Yes
Yes
R2.1.1 does not specify the magnitude of the required voltage excursion, i.e. 1%, 2%, etc. Is their a specific required voltage change level?
Yes
No
Individual
Tom Flynn
Puget Sound Energy
Yes
No
Please clarify whether rate of change of frequency relaying is required; or alternatively, if the required setting of not less than 2.5 Hz/sec is only applicable IF rate of change of frequency elements are available and enabled.
Yes
Yes
This would require detailed information from the manufacturer of a combustion turbine. The requirement appears to be entirely reasonable for hydro installations. We expect it would take two years to complete this work.
Yes
No
Individual
Jeanie Doty
Austin Energy
No
Yes
Yes
Yes

ERCOT performs computer modeling based data (RARF) provided by Generators. Please consider allowing an exemption or alternate methods for older unit dynamic data as the information for these older units is not always available. ERCOT has used typical or generic modeling parameters for these units.
Yes
Yes
Yes
The curves in Attachment 1 are more restrictive than the current ERCOT Operating Guide requirements. The equipment impact of this new requirement requires additional internal review, before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
The equipment impact of this new requirement requires additional internal review before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
No
Group
Luminant Power
David Youngblood
No
Yes
Yes
No
Yes
Yes
No
Luminant believes this standard should only apply to voltage and frequency relay settings.
No
Luminant believes it may be technically possible to design a new generating unit or facility to ride through a low voltage event even though the cost to do so may be prohibitive and impractical. However, Luminant does not believe it is reasonable or achievable to expect the Generator Owner to be able to maintain those capabilities in perpetuity due to equipment deterioration and aging over time even though proper maintenance practices were implemented.
No
Luminant believes the settings are reasonable and achievable for relay settings only.
No
Individual
Michael Falvo
Independent Electricity System Operator
No

No, we are not aware of any. Similar to our comments on MOD-027-1, the Applicability Section of draft MOD-026-1 standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the “generating units” suffice to generally include all types of energy resources?
We are a bit surprised and disappointed that the SDT asks this question. The posted MOD-026-1 Draft 2 is a clean version, not a redline version from last posted, making it difficult for readers to identify where the previous requirements are contained in the revised draft. We understand that a reformatting may render tracked changes to be convoluted and hence a clean version may be a better option. However, in doing so, the SDT should provide a mapping document to show where the previous requirements are mapped into the revised draft standard. Whether or not any requirements were omitted could have been and should have been identified by the SDT through the mapping process rather than by the commenters.
We do not have an opinion on which standard should contain this as long as synchronous condensers are verified.
Yes
1. We do not agree with some of the requirements. i. R1: Standards should stipulate the “what’s” not the ”how’s”. To avoid the perception that the requirement is prescribing the “how”, we suggest simplifying the language of Requirement R1 by replacing “Instruction on how to obtain” with “Instructions for obtaining”. Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process. ii. R2.1: The phrase “models acceptable to its Transmission Planner” begs the question on what is deemed acceptable and what if the GO disagrees with the TP’s determination. To address the two issues, we suggest adding a requirement for the TP to specify the models requirements (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to “in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). iii. We are not sure why Requirement R5 is needed. First of all, it suggests that a Planning Coordinator may request the GO to perform a model review where the request can be technically justified. We wonder if the requirement really means “Transmission Planner” rather than “Planning Coordinator” since TP as the requester and model user is specified throughout the standard. Secondly, if it is indeed TP that was meant to be the requester, then would this request already been covered by Requirement R3? If not, what are the technical justifications? They are not specified in R5, unlike its R3 counterpart. Please clarify and/or revise the requirement as appropriate. iv. R6 stipulates the criteria that may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model. A computer model may fail to initialize due to reasons other than the submitted excitation control system and plant volt/var control function model itself; a no-disturbance simulation may not result in negligible transients due to other reasons; and finally, a disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. System damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three sub-requirements. We suggest this requirement be removed. Further, in many jurisdictions the setting and tuning of excitation control systems and associated power system stabilizers, etc. are determined by the Transmission Planners (or Planning Coordinators); the GOs would simply provide the equipment and set them according to the TP’s specification. In this standard, the responsibility is for the GO to verify that the model reflects the actual response of the tested equipment, whose settings have been determined prior by the other responsible entity. 2. In the previous posting, we provided 2 comments which in our view, have not been duly and satisfactorily addressed by the SDT and we would like to reiterate them here: i. We suggested that at a minimum, the generator's basic characteristics such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), voltage regulators, turbine-governor systems, etc. as stipulated in MOD-013 that support modeling for dynamic simulations should also be verified. A good excitation system model without a valid generator model will not provide the assurance that the

simulation results are valid, which may hurt reliability. In response to this comment, the SDT indicates that: "[it] agrees that appropriate dynamic models are needed for generators, exciters, PSS, and governors. The SDT believes that when testing personnel verify the excitation system model data, they also provide verification of the generator model data. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. The governor model is not verified with the excitation system model since it requires a frequency excursion. Verification of the governor model will be addressed by the MOD-027 standard. Experience indicates verification required by the MOD-026 standard often results in discovery of significant changes to the representation of the generator and exciter, suggesting that model verification provides significant reliability improvement." Generator model parameters need to be verified based on tests conducted during both turbine/governor model verification as well as excitation system model verification. We are however not convinced that those tests that need to be performed during the excitation system model and data verification process, to verify certain portions of the generator model parameters will be conducted as a matter of course. We therefore reiterate our view that the verification of generation model parameters needs to be included within the scope of this standard and we urge the SDT to consider our comments again. ii. We suggested that in some areas on the interconnection, such as those that are sparsely populated, performance of generating units at less than 100 MVA might be critical to reliability. The criteria to allow the TP and PC to identify these units could include: a. A 5% or 10% deviation of any or several of the excitation system's parameters/settings could make an otherwise stable simulation to be unstable; b. Use of generic models for the excitation system or generator would make an otherwise stable simulation to be unstable. c. Other changes or incorrect assumptions for the excitation system or generator would make an otherwise stable simulation to be unstable. The SDT responded that: "After reviewing provided details, the SDT encourages you to review the new process draft (reference Requirement R2) and provide additional comments as appropriate." Requirement R2 does not contain any provision that a TP (or PC) can request for model verification of units that do not meet the Applicability criteria. Throughout the standards, such a provision does not exist. This could leave room for system to exhibit unstable performance for reasons indicated in our previous comments. We urge the SDT to reconsider our proposal.
No
We generally agree with these definitions, but do not see the need to specify the band values, i.e. ±0.5 Hertz and ±5%, in them. The two definitions should stay clear of any specific values, which can be specified in the standard, to remain valid if and when the band values vary.
Yes
No
We believe the SDT meant R5, not R4, unless R4 is a sub-requirement or a part of R3 (which seems to be the case by the way R4 is worded) and a format error resulted in R4 becoming R5. We do not support the provision of such an estimate. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3 (which, by the way, should be modified as we suggest below), the TPs can apply the following relevant assumptions: a. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; b. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon?
Yes
First of all, we believe the SDT meant R6, not R5. Also see our editorial comments under Q3, above.

We believe this requirement is achievable for most cases. However, provision should be given to the Generator Owners which for specific technical reasons are unable to design a generating units to comply with the requirements. As worded, R6 does not contain this provision.
Yes
1. R3: Please clarify the meaning of the expression “non-protection system equipment”. Does it mean “a limitation imposed by equipment other than the protection system”? Or does it refer to generating units that are NOT equipped with frequency/voltage protective relays? In the latter case, how would the GO determine that the units that are not so equipped are unable to meet the criteria in Requirement R1 or R2? In our view, units that are unable to meet these criteria are those that are equipped with frequency/voltage protective relays and whose trip settings do not meet the criteria specified in R1 and R2 for specific technical reasons that are communicated to the Transmission Planners. For units that are NOT equipped with such protective relays, the suggestion that any of them may be unable to meet the criteria in R1 and R2 could be those which in the past have tripped before the thresholds. However, unless a unit repeatedly trips under like circumstances, isolated incidences do not provide sufficient evidence to arrive at a conclusive determination. And for those units that are NOT equipped with the protective relays and have never tripped before the thresholds, there is no telling whether or not they can meet the criteria. For the above reasons, we suggest the SDT to revise the R3 to convey the requirement that the GOs shall provide the technical reasons for not meeting the R1 and R2 criteria only for those units that ARE equipped with the protective relays and ARE set at different thresholds. 2. As indicated in our comments under Q3, we think R4 is a sub-requirement or part of R3 since R4 mandates the GO to respond to the listed entities within 30 days of receiving a request, and that in the requirement there is no mention of “what” the response should entail. The “what is stipulated in R3. 3. R7: We assess that this requirement duplicates with what we interpret as the intent of a good part of R3, i.e., to provide the listed entities with the settings of the frequency/voltage protective relays. Regardless of whether or not a GO is able to meet R1 and R2, it should be obligated to provide the generator protection trip settings to these other entities for modeling purpose (consistent with our comments under Q3). If a GO sets the protective relays at values that do not meet the R1 and R2 criteria, then it should be obligated to provide the technical limitations that form the basis of the deviation. This requirement thus should come after R1 and R2, and replaces the as written R3 for reasons that we mention in our comments in (1), above.
Group
Progress Energy
Jim Eckelkamp
No
Yes
Yes
No
No
PE suggests using the term “exceeding” rather than “exceedance”. PE furthermore believes that 60 HZ +/- 0.5 Hz is appropriate but does not agree that +/- 5% for voltage is an appropriate bandwidth for “normal”. Any threshold must agree with VAR-002. Along with a clarification of what a voltage schedule is (i.e. target, bandwith).
No
Requirement R1 subsection 1.5 is not clear as to when rate tripping is acceptable or not. Is it OK to trip at 59.6 Hz if the ROC is > 2.5 Hz or is this ROC trip acceptable only outside the no trip zone.
No
This appears to actually refer to R5. PE submits the comments below with the assumption that this question is directed toward R5: PE agrees with the requirement of R5 in general, but disagrees with the approach to the extent that R5.1 contains two options for GOs’ providing of information regarding

voltage excursions, one of which is problematic. Specifically, the requirements of Attachment 2 are too stringent and cannot be used by the majority of GOs, which leaves the second option as the only feasible method. The second option, provision of a voltage profile “at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault described by dynamic simulation provided by the Transmission Planner”, puts the responsibility back on the Transmission Planner. Requirement R5 is intended to aid Transmission Planners in providing information on Generator models needed for Transmission Planning analyses, and yet as it exists the only option for provision of the information is a hindrance to Transmission Planners rather than an aid. PE requests that the SDT simplify the language to merely state that GOs have an obligation to provide information that the TPs request.
No
This appears to actually refer to R6. PE submits the comments below with the assumption that this question is directed toward R6: The ride through voltage profile in attachment 2 is not achievable for either new or existing facilities. The issue is not the relay protection but in the capability of the auxiliary equipment (such as motor contactors, coal feeders, instrument sensors). I do not know of any motor control contactor that will hold in when voltage goes to zero. The energy that is stored in the coil holding the contactor in place is rapid returned into the system during a time of fault. While the short circuit contribution of motors and contactors may last up to .2 seconds the majority of the stored energy is returned in the first 1/5 of the decay curve. The requirements that are specified in this standard are outside the IEEE and ANSI standards associated with manufacturing equipment used in power plants, while manufacturing of equipment to specialized standards MAY be possible the cost would be extremely high and in some cases may not be possible.
No
The ride through capabilities should be within the IEEE and ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)”. Standards associated with manufacturing electrical equipment
Yes
Forcing the utility to delay fault clearing (a three phase bolted fault at the point of interconnection causing a zero voltage) will increase the damage to the generation facility caused by the fault. Protective relay schemes have two primary objectives, to clear a fault rapidly to minimize the impact on the Bulk Electric System and to prevent (minimize) the damage to the faulted component and the components close to the faulted component. By forcing utilities to keep a generator feeding a fault of the magnitude implied by attachment 2 of PRC-024 the regulation may increase the costs of maintaining the generator. Additional inspections after a fault may be required to assure no internal damage occurred during the event that would not be required if the generator could be isolated from the fault more rapidly.
Individual
Dale Fredrickson
Wisconsin Electric
No
Yes
Yes
Yes
Section A Effective Dates: In 5.2.1, replace “30% of its applicable units” with “20% of its applicable units”. There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years. Section B: Requirement R1: Replace “Each TP shall provide the following INSTRUCTIONS AND DATA to its GO…” with “Each TP shall provide the following DATA to its GO…”. On the first two bullets, remove the phrase “Instructions on how to obtain…” The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace “Any of the GO's existing … model data“ with “All the GO’s existing … model data…”. Since the TP already has this data, it is more straightforward to simply provide all

relevant data to the GO. Requirement R2: Replace the first sentence with, “Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models…” The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3. In R2.1.1, replace “Documentation demonstrating the … model response matches the recorded response” with “Documentation WHICH MAY BE USED TO DEMONSTRATE that the … model response matches the recorded response”. In R2.1.3, 2.1.4, and 2.1.6 replace “model structure” with “block diagram”. In Requirement R3, replace “90 calendar days” with “180 calendar days”, to allow more time to work through the technical challenges relating to these models. In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace “walk down” with “inspection”. Comments on Attachment 1: 1. Remove the note which says, “Note that local grid codes may specify…”. 2. Under “Conditions” for existing generators, it is not clear why there are references to both a ten year period and an eleven year period. Also, replace “Subjected to an activity resulting in an alteration of the response of the excitation control system” with “Changes to control system or parameter values”. 3. Under the exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under “Periodicity” for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis. Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.
No
The system can operate without problems within +/- 5% of nominal system voltage under normal conditions. Generator capability curves allow for continuous operation between 95% and 105% of rated voltage. Therefore, the operating band for voltage needs to be expanded beyond +/-5%, perhaps as high as +/- 10%.
Yes
No
(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Yes
1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". 6. In R2 (second sentence), replace "shall set its protective relaying not to trip … " with, "shall set its

protective relaying to avoid tripping ..."
Group
BC Hydro and Power Authority
Patricia Robertson
No
The Applicability section includes Generator Owners and Transmission Planners. If an entity is a Generator Owner, they will meet the NERC Compliance Registry Criteria including MVA criteria. Including phrases in section 4.2 such as “The remainder of the plant as an aggregate”, and “For all interconnections: Any technically justified unit requested by the Planning Authority” is confusing and it seems to be expanding the criteria. For example hydroelectric units that don’t qualify an entity as GO may be captured here. Also, for the aggregate, a GO may not be able to model and verify the aggregate consistent with the method used by TPs.
Yes
Yes
MOD-025 includes synchronous condensers. This doesn’t appear to be consistent with the strategy for MOD-026?
Yes
1. This standard is still not clear in terms of what constitutes verification of the model and what are related obligations of parties involved. Specifically, it is not logical or technically feasible to request GOs to address any problems with “usability” that TPs may have with the excitation control system model applied in their simulation software. Related Requirements are R3 and R6. The GOs provide accurate model data of their systems during the generator interconnection and facility registration process. Detailed base-line testing is done at that time. For subsequent verifications, GOs would use certain software tools, most likely not the same that the TPs are using, to simulate excitation control system response. This simulated response would be compared with actual equipment response. If traces (signatures) match closely enough, the model is verified. The GO would submit required information to the TP as per R2. At this point, the GOs obligations should be over and subsequently, the GOs should not have a compliance obligation to take part in resolving any issues that the TP may have with the “usability” of their models. Any further involvement by the GOs should be in the spirit of good will and professional courtesy among the parties. In conclusion, GOs should not have compliance obligations to resolve issues related to “usability” of models applied in the TPs power system simulation tool. 2. The idea that GOs “own” the models and are responsible for model modifications and verification still remains controversial for a number of reasons: a. GOs have little need for models and many do not have any expertise in modelling. b. Software tools used by GOs or external consultants for commissioning and verification purposes would not be the same as the tools used by TPs c. TPs would have to work on tuning so the whole exercise would not have a particular value in a technical sense. This is supported by the NERC Event Analysis & Information Exchange staff who noted during the first comment period: “Although verification (not validation) of generator equipment settings and testing should be the responsibility of the GO, validation of generator models response to actual system events should be done by the Reliability Coordinator.” Also, NERC’s white paper “Power System Model Validation”, Dec 2010, expands on this view. It implies that the ultimate responsibility for the usability and accuracy of dynamic models and how they perform in relation to the overall system model is the responsibility of the Transmission Planners, Reliability Coordinators or similar entities. 3. We recommend revising the wording in Requirement R2.1.1 for improved clarity. The way it is written, it strongly implies that the method of verification is based on system disturbance (ambient) monitoring: “Documentation demonstrating the unit or plant’s model response matches the recorded response for a Voltage excursion at the generator or plant point of interconnection. 4. Requirement 5 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner? Also, we recommend revising the wording in Requirement 5 for improved clarity. 5. Attachment 1 Column 6 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner?
Yes
Yes

No
The requirement R5 (R4 is a typo in the Question) is ambiguous and redundant. What does “estimating” mean? One could infer that the GOs are actually required to do what TPs are normally doing as part of their studies: estimating (assessing, simulating) the performance of units during frequency or voltage excursions. In order to fulfill requirements R1, R2 and R3 of this standard, GOs have to do engineering analysis and studies to develop adequate protection settings and to assess other non-protection systems and equipment. By declaring compliance GOs commit to keeping their units on-line during defined frequency or voltage excursions. In the case that a GO identifies a particular limitation, they would inform the TPs so that this limitation is taken into account in system studies. Hence, the goal of the standard would be fully met without R5. In light of the above, the requirement R5 should be removed. Technically it is of little value, if any, becoming just an unnecessary burden for GOs. In compliance terms it could be a source of perpetual confusion and disputes.
Yes
Frequency and voltage excursions specified in this standard are reasonable and actually less stringent then certain regional or area requirements. Generating facilities designed in line with industry practices and applicable standards should be able to ride through such disturbances. Lastly, it is in GOs best interest to have a robust design for new generating facilities.
Yes
Yes
1. R2 introduces Remedial Action Schemes (RAS) as an alternative description. We recommend keeping to Special Protection System and leaving RAS in the NERC glossary. 2. We recommend a consistent use of the terms Planning Coordinator and Planning Authority. In the Purpose of this standard, Planning Coordinators are referred to. In the NERC glossary, under Planning Coordinator it says “refer to Planning Authority”. The compliance registry list includes a column for Planning Authorities. The NERC Reliability Functional Model version 5 discusses Planning Coordinators only. Is the term Planning Coordinator going to replace Planning Authority?
Individual
James R. Keller
We Energies
No
Yes
Yes
Yes
Section A Effective Dates: In 5.2.1, replace “30% of its applicable units” with “20% of its applicable units”. There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years. Section B: Requirement R1: Replace “Each TP shall provide the following INSTRUCTIONS AND DATA to its GO…” with “Each TP shall provide the following DATA to its GO…”. On the first two bullets, remove the phrase “Instructions on how to obtain…” The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace “Any of the GO's existing … model data“ with “All the GO’s existing … model data…”. Since the TP already has this data, it is more straightforward to simply provide all relevant data to the GO. Requirement R2: Replace the first sentence with, “Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models…” The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3. In R2.1.1, replace “Documentation demonstrating the … model response matches the recorded response” with “Documentation WHICH MAY BE USED TO DEMONSTRATE that the … model response matches the recorded response”. In R2.1.3, 2.1.4, and 2.1.6 replace “model structure” with “block diagram”. In Requirement R3, replace “90 calendar days”

with “180 calendar days”, to allow more time to work through the technical challenges relating to these models. In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace “walk down” with “inspection”. Comments on Attachment 1: 1. Remove the note which says, “Note that local grid codes may specify…”. 2. Under “Conditions” for existing generators, it is not clear why there are references to both a ten year period and an eleven year period. Also, replace “Subjected to an activity resulting in an alteration of the response of the excitation control system” with “Changes to control system or parameter values”. 3. Under the exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under “Periodicity” for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis. Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.
No
Yes
No
(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Yes
1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..."
Individual
Linda Horn
We Energies
No
Yes

Yes
Yes
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No
The system can operate without problems within +/- 5% of nominal system voltage under normal conditions. Generator capability curves allow for continuous operation between 95% and 105% of rated voltage. Therefore, the operating band for voltage needs to be expanded beyond +/-5%, perhaps as high as +/- 10%.
Yes
No
(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
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Group
SERC Generation Sub-committee (GS)
Joe Spencer - SERC staff
Yes
The GS is not responding to MOD-026
Yes
The GS is not responding to MOD-026
Yes
The GS is not responding to MOD-026
Yes
The GS is not responding to MOD-026
No
The SERC generation sub-committee (GS) believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to “… exceedance of system voltage beyond the applicable voltage schedule.”
Yes
The GS recommends that the applicability section be revised from “GO” to “GO’s that have frequency and voltage protection functions activated to trip a new/existing generation unit.” Also, while the GS does, in general, agree with the content of footnote #2 on page 2 (under R1), we believe that this is verbiage is better placed in the implementation plan because it puts commercial considerations into the standard.
No
The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
No
This appears to refer to R6. The proposed bands would need to be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant designs and no concerns were identified. However, It is not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) have been and are normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)”as follows: a. Normal Conditions: ±5% Continuous Duration b. Emergency Conditions: ±10% not specified Duration These Criteria are

currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
No
Comments: The GS proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
Yes
During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: • Important Existing nuclear plant settings are inside the published no-trip bands • How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. • Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform it's function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2. “The comments expressed herein represent a consensus of the views of the above named members of the SERC Generation Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Group
Idaho Power - Power Production
Tim Brown
No
We agree with the need to include wind generation in this standard, however the applicability section seems to be overly complicated. We do not see the relevance of the 80% of connected generation as discussed above. We believe that the NERC generator registry/ BES criteria would be clear and appropriate continent wide for this standard and with many other standards. In addition, we believe that Section 4.2.4 is too open-ended. It appears to open the door for the verification of any sized machine that does not match a response, or for other open-ended reasons. Too open-ended and subjective.
No
Yes
The Requirements direct the GO to send responses, data, inquiry to the Transmission Planner. Should this really be to the Transmission Operator? We understand that the TP will ultimately use the data, however, we believe the data and communications should flow through the TOP. Specifying timeframes for both recording data and providing results is cumbersome. More properly, timeframes

and periodicity should be specified only on providing results. If necessary, a limit on the age of the recorded data could be specified. R6.1, R6.2 and R6.3 seems overly prescriptive and of little value. In the process of verifying model data and comparing to recorded results, those 3 conditions are met. If the Transmission Planner has concern about their ability to use the model data in their studies, it is more properly addressed either without specific criteria, or with the specific criteria that the Transmission Planner is unable to reproduce the simulated response contained in the model verification. The requirement of several responses to submit plans to test within 365 days and submit with 180 days (per the periodicity table) seems too long from an system reliability standpoint, particularly where it is the outcome of an observed response to an actual event not matching the predicted response. On the other hand, scheduling a test and model verification within a shorter period of time would be challenging for the GO, particularly those that rely on outside contractors for the model verification work. Any request to verify or retest due to an observed response not matching an actual event should be accompanied by full electronic information (recorded data, simulated output, simulation conditions, model data used by TP). Requirement R1. The first two bullets appear to allow variation between Transmission Planners on acceptable models and software. The list of acceptable models needs to standardized at least across the RRO. In addition, the GO should not need to adjust the model validation and verification work based on the software that the TP uses (what happens when the TP uses multiple software packages?). If the SDT feels there is a need to specify acceptable software, then that should also be standardized. The third bullet should read “All of the Generator Owner’s existing” instead of “Any”. The TP should provide all the information in its database regarding the GO’s facilities, not just “any” piece of it. R2, 2.1. Reference to “models acceptable to its Transmission Planner” is inappropriate, see previous comment. The list of acceptable models needs to be standardized, although situations (rare) where the Generator Owner and Transmission Planner jointly agree to use a model not on the list should be allowed. In particular, the Transmission Planner should not restrict use of any the models on the standardized acceptable list.
No
Basing the voltage excursion definition on scheduled voltage is troublesome, as “scheduled” voltage can change over time, and in some cases, varies seasonally. Protection and limiter settings are not, and should not, be adjusted to address varying schedules. That said, simply using nominal voltage instead of scheduled voltage is probably not the answer either, as it is not unusual to have POI scheduled voltages of 1.05 pu or higher.
Yes
Yes, R1 and R2 do make it clear that the GO does not have to install or set these functions however we believe that the standard should clarify better that the standard is applicable to all “voltage-based” protection functions such as the backup impedance function (21) and the voltage controller (51C) or voltage restrained (51V) Overcurrent functions. These functions may operate if not coordinated properly. We do not believe that was made very clear. Particularly for units that fully compliant with this standard, providing an estimate of unit performance during a frequency or voltage excursion is burdensome and unnecessary. If the event is within the parameters of the standard, the planner can rely on the unit staying on, if not, the planner should model the unit as a trip. In particular, we are unaware of any methodology that would be capable of providing an “estimated probability”. Protection consistently operates as designed and configured.
No
This requirement should not exist. Generator Owners are required to comply will all approved NERC and RRO standards. It is the responsibility of the Generator Owner to see that the plant is built according to specifications which should include all approved NERC Reliability standards governing power plants.
Yes
Yes
In section 2.1.1, we believe that the “three phase transmission system zone 1 fault” should be clarified. Is the zone 1 referring to the generator relay backup zone 1 element? The zone 1 element of the interconnection station line protection relays? Shortest line? Longest line? Another zone 1? Also, the language was a little confusing, is this an if-then statement? Since the voltage ride through curve apparently applies to all conditions (both operating and various fault configuration), reference to the

“three phase transmission system zone 1 fault” implies a limitation to applicability that is not intended, and the reference should be deleted. For R3, because the time horizon for this standard is long-term planning, we believe the 30 day communication requirement is not necessary. We believe 180 days is more in line with other reporting time frames with modeling related standards. We also believe that the equipment limitation expiration section is not needed. A simple statement stating that the when the limitation is no longer valid, the RC, PA, etc should be notified. For R6, we believe it is unnecessary to have different requirements for existing and new units. We do not see the need for performance requirements for new units. We believe this standard should be a relay settings standard, with generator performance being considered in modeling standards. R7 is burdensome to both the Generator Owner and to the receiving entities, and also prone to causing confusion. The entities proposed to receive the protection settings (RC, PC, TO, TP) would face a difficult task to be able to properly interpret the relay settings sent. The Generator Owner is the proper entity to determine the relay settings to remain in compliance with the standard. In addition, the requirement to transmit the settings within 30 days of changes is burdensome and unnecessary. Draft PRC-019-1 properly address the issue of coordinating settings with machine capabilities, and PRC-001 properly addresses the issue coordinating settings with the TO.
Group
Westinghouse
Scott Sweat
No
Yes
Yes
No
Yes
Yes
No
a. This is for requirement 5 not requirement 4 b. We cannot evaluate the performance of units during frequency and voltage excursions at the transmission interface point, only at the generator and 6.9kV bus level where the auxiliary equipment interface exists. Therefore, the frequency and voltage excursion profiles would be different than those submitted by the RC, PC, TO or TP. Also, 30 days is too short to perform a detailed analysis on plant performance during the frequency or voltage excursion. Further evaluation would be required for the transformers, turbine and auxiliary equipment to determine satisfactory operation in the long time periods encompassed in the "No Trip Zones".
No
a. This is for requirement 6 not requirement 5 b. It is uncertain that the requirements, when translated to the 6.9kV AC distribution system and below, can be achieved with the equipment installed in new generating facilities. Most motor specifications do not require demonstrated operability below 75% motor rated terminal voltage or >5% deviation in rated frequency. Additional vendor testing would be required in order to effectively demonstrate equipment design capabilities. Additionally, plant performance has not been evaluated for the entire range of frequencies in the "No Trip Zone". More analysis would have to be performed in order to verify acceptable plant operation in these frequency bands.
No
Due to the excessive duration of the +/- 10% voltage excursion, it is uncertain that many new manufactured turbine generators will be able to meet the V/HZ limits set by the manufacturers. Detailed studies would need to be performed to determine the ability of newer turbine generators to ride through these conditions.

No
Group
SPP Reliability Standards Develpment Team
Jonathan Hayes
No
Yes
Yes
We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
Yes
The applicability of 100 MVA matches MOD027-1 but is inconsistent with MOD025-2 or PRC 019-1. We feel like these should be consistent in every standard included in this project. VSLs for R4 footnote reference needs to be deleted since there is no footnote to reference. We would like to see a more consistent approach to the comment forms and the standard itself. It seems there is room for clean up in the posted standard/comment form.
No
We believe that +-5% is ok for normal operating conditions but this doesn't address contingencies being taken or a time frame. The curve in attachment 2 doesn't seem to correspond with the definition as proposed. We are also unclear about the term continuous. We think this means from 0 to infinite. This graph indicates at 600s one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria shows that during a contingency we can operate at a +5% -10% bandwidth.
No
We agree that R1, with the footnote mentioned, makes it clear that the Generator owner would not be required to have protective relaying installed or set for these functions. As for R2 we feel that footnote 1 should also be referenced in R2.
No
The question should mention R5 and not R4. We feel like the planners shouldn't have to request this data and should be supplied for each unit once and again if the characteristics change. We also feel like 30 days might not be appropriate time to gather such information and would suggest that 90 days would be a better time frame for supplying this data.
Yes
Question should read R6 not R5. We feel that as long as everyone knows about these requirements ahead of time that there shouldn't be an issue with achieving these requirements.
No
We would like to see the technical background/justification of why the timeframe of 600s was chosen. We understand seeing the reasoning to expand it from 4s, but 600s (10 Minutes) seems extremely too long for voltage recovery. From a planning perspective 15 cycles (.25seconds) is standard for voltage recovery. Holding .9 from 3s to 600s could prove difficult if full load on unit and might not be enough bandwidth before you hit a loss of field relay. If enough current is provided to the field it will cause this relay to trip instantaneously. Not sure that taking a 10% hit during this instance will work.
Yes
Would like to see a more consistent approach to the comment forms and the standard. It seems there is room for clean up in the posted standard/comment form.
Group
MRO's NERC Standards Review Forum
Carol Gerou
No
Yes

No
Synchronous condensers are installed at locations where they are specifically needed for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.
Yes
We have a number of questions and concerns as follows: • It is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? • We have concern about whether this Standard is cost effective for the industry. The transient stability dynamic modeling for excitation control was traditionally developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts required by this standard are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more. • MOD-026 does not account appropriately for the differences between distributed generation and single shaft generation. Aggregate generation that do not have a common excitation and regulator control system (such as wind farms) may pose serious difficulties in meeting system disturbance and / or staged testing. A staged test can be performed for a single shaft unit. However, wind farms may not have a centralized plant or wind farm voltage controller. If that isn’t the case, entities may be forced to actually shock the BES to force a disturbance large enough to force a wind farm response. If this is true, then exceptions need to be made. • In addition, there are concerns about the technical development and accuracy of current wind farm models. It is not certain that all manufacturers have fully developed all of the control system models necessary to meet these standards. Type III and Type IV PSS/E generic standard models have all been benchmarked. What has not been included in these models are the wind farm park voltage controllers. While local turbine model controllers will dominate the short term response, the longer term park voltage controls are not represented. Therefore if the models aren’t available, then model traces can’t accurately match reality. Older wind farms will not have appropriate models. In short, the state of wind farm models hasn’t completely developed to match wind farms and specific exemptions for wind farms need to be added to the standard at a minimum.
Yes
No
The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under R3 which covers equipment limitations either.
Yes
This question seems to be referring to R5 rather than R4.
No
If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Yes
Do not have an alternative value to suggest.

Yes
It is not clear what the basis for the requirement of R3 with regard to a 10% or more increase in capacity would lead to an expiration of an equipment limitation as the change that results in the capacity increase may not be related in any way to the origin of the equipment limitation.
Individual
Jon Kapitz
Xcel Energy
No
Yes
Yes
No
Yes
Yes
Yes
Yes
It is Requirement R6 that requires new units to ride through excursions. We believe it is technically feasible to design generating units to reach a high probability of riding through these excursions. However we do not consider the additional expense necessary to meet this objective to be of value to our customers given the infrequency of occurrence of excursions of the magnitude described in this standard. Excursions of this type have occurred on our system and some generating units have tripped due to the excursion, but it has never led to a cascading outage. In addition, we believe new plants should not be considered in violation for a trip during an excursion if the GO can identify the reason for the trip and correct the deficiency. If the standard is made mandatory, we believe that an additional five years should be allowed for new units so that the A/E firms can develop proper design criteria for plant auxiliaries and equipment OEM's to develop designs that can handle the requirements
Yes
No
Individual
Michael Brytowski
Great River Energy
No
Yes
Yes
Yes
We appreciate the drafting team's consideration in Section A.6 to allow a unit that has already verified its excitation system to be considered compliant. However, it is not clear how this section helps. How does the Generator Operator demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff be sufficient? Will the regional

entities be willing to validate that they have confirmed regional criteria? This standard is overly administrative by memorializing the interactions between the Generator Operator, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck. They are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are needed to accomplish the purpose of this standard. They are: ne requirement for the Generator Operator to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6. This just represents one of the issues with memorializing the interactions between the Transmission Planner, Planning Coordinator and Generator Operator in the standards. Because the tests to verify the excitation model can be expensive, there should be a demonstrated need to perform a test. Summaries of field test results posted with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit. That does not even include opportunity costs from lost energy sales should the test cause the unit to trip. Thus, if there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the generator operator should be able to wait for a system disturbance appropriate enough to verify its model. Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Operator should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.
Yes
No
The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under R3 which covers equipment limitations either. It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why?
No
Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the Generator Owner's best interest to be responsive. Thus, this requirement is not necessary.
No
If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Yes
Yes
It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The

red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the “clean” documents. Thus, it is not clear what is being voted on. For example, the “clean” document shows that there are five parts with Requirement R1. The “redline to last posted” document has four subrequirements under the main requirement R1. The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point. Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
No
Individual
Greg Rowland
Duke Energy
No
However, an exception should be made for variable energy resources for which models have not yet been fully developed and accepted. Techniques for validation of these devices have not been developed similar to generator excitation model validation tools (EPRI PPPD).
Yes
No
These types of reactive resources should be included if of a sufficient size to impact reliability.
Yes
1) If System Models are poor today, it is probably due to a lack of understanding on what models are required, setpoint control and what changes need to be communicated to Transmission when plant projects are done. Periodic reverifications are probably not the right way to ensure reliability. Instead there should be an event-based revalidation requirement, such as if you replace the control system or recalibrate the control settings on an existing unit, replace the rotating exciter or rewind a generator. An approach where there is an initial validation effort to get today’s models consistent with installed equipment is clearly needed. However, assurance that future models will remain valid requires that there is a program in plant project processes to revalidate when appropriate, and thus a requirement to show that the company has the needed project processes and has followed that process is the right way to approach this. 2) There needs to be a requirement for the entity responsible for actually

inputting the models and data to do so on a timely basis. This should be an annual update of data to be submitted to the interconnected models. As currently written, there is a requirement for the GO/GOP to submit information, but they do not input directly into the interconnected system models. MOD-010, MOD-011, MOD-012 and Mod-013 don't currently ensure that data is incorporated in a timely fashion. 3) Since GO/GOPs do not always have electrical system modeling expertise, nor participate in interconnected system models groups such as the MMWG which sometimes changes how equipment is modeled, there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF are considering a collaboration to do so. 4) Identically designed generation units are identical in control response, independent of site location. New techniques for validation eliminate the impact of the grid on the validation efforts. Thus, credit for sister unit validations should be available independent of the location of a unit. 5) Discussions during the EPRI PPPD users group indicate certain parameters in the models are temperature sensitive, and thus verification and adjustment of models should be done under conditions that reflect normal operating conditions. An on-line voltage step test or DFR data from an event is the best way to perform the validations. It's not clear if validations against off line tests would actually make the models worse, but the industry should be encouraged to do validations on line near full power. 6) R2, 2.1.3 Total unit inertia should be given to include all coupled rotating elements. The way this is currently worded, it could lead generators to only provide the generator H values. 7) Footnote 4 – Delete the phrase "or evidence that the simulated unit or plant response does not match measured unit or plant response". Otherwise this standard could be made applicable to a small unit that has no impact on reliability.
No
We are not sure what is the purpose of the voltage excursion definition in this standard. Is excursion measured versus scheduled voltage, or equipment rating?
Yes
No
Should be R5. We question the value of this requirement, and how the TP use the probabilistic information in any TPL analysis. It's unclear how compliance with planning requirements would be demonstrated. The planner needs to know under what voltage/frequency conditions a unit will trip so that when those conditions are attained in the model the unit will be turned off. Generator owners/operators need to make their best efforts to determine the conditions and provide it to their TP's, updating the information as plant design changes occur or operating history indicates the conditions have changed. Having a time estimate as specified in R5.1 does not provide the voltage/frequency threshold that the planner must know so that the unit can be tripped when those conditions occur in the model, no matter what time those conditions occur.
No
This appears to refer to R6. The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 "American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)"as follows: a. Normal Conditions: ±5% Continuous Duration b. Emergency Conditions: ±10% not specified Duration These Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second is to utilize expensive voltage regulation devices, normally not utilized at

power generation plants. This standard shouldn’t dictate a solution to the situation where a generator goes offline due to low voltage on the transmission system, because in many cases the generator going offline may not be a problem for the overall transmission system. In situations where it is a problem, a collaborative effort between the Transmission Planner and the Generator Owner would be the best approach (see AREVA white paper that has been provided to the SDT). It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
No
The LVRT portion of the curve between 0.4 seconds and 3.0 seconds should be 0.90 voltage PU. Electrical powered devices at the plant will begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Yes
During the drafting process, quite a bit of feedback was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated, using the allowed operating bands developed as a setting coordination. The concerns include: • Existing nuclear plant settings are inside the published no-trip bands • How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. • Why is a voltage ride-thru criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be long enough in duration for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar restrictions may also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC Reliability Standard NUC-001-2. PRC-024-1 should allow nuclear power plant interface requirements to be managed under NUC-001-2. (See PowerPoint and AREVA white paper provided to the SDT).
Individual
Melissa Kurtz
US Army Corps of Engineers
No
Yes
Yes
No
No
Yes
Yes
No
R5 applies to existing units. This requirement seems vague and subjective - recommend clarification. Please clarify the term "less stringent" - do you mean 'in the no-trip zone' or 'outside the no-trip zone. How will the information be used and what are the implicatios if the response is not satisfactory? R6 applies to new units - I have no comments on R6.

Yes
Yes
-R2.1.1 - 'not to exceed 9 cycles' this wording is confusing and needs to be clarified. -Suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity included in MOD-026, Requirement R3. -R7 seems to be a duplicate requirement with PRC-001 - Implementation comment - from an implementation perspective it would make it easier if all standards in Project 2007-09 had the same implementation schedule.
Individual
Steve Rueckert
Western Electricity Coordinating Council
Yes
Requirement R1, first bullet. Grammatically, should the word model in the first bullet be models? Requirement R4 requires the Generator Owner to provide revised model data or plans to perform model verification. The way I interprete the wording of Requirement 4 is that the model data or plans to perform model verification are due within 180 calendar days. If the GO provides plans to perform model verification and submits the information on their plans within 180 days, is there any time limit as to when the model verification must be performed? If so I suggest it should be included in the language of the Requirement. If the actual verificatio must be done within 180 days this should be clarified becasue right now it just looks like only the plans have to be submitted within 180 days.
No
WECC is requesting a regional variance to Requirement 1 that reflects the generator performance requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan. WECC's continuouse operations zone is between 59.4 hZ and 60.6 Hz. Therefore, WECC will need a regional definition of Frequency Excursion to be an exceedance of system frequency beyond a continuous operating band of 60±0.6 Hertz.
Yes
No
The question above appears to be referring to R5, not R4. R5 has the requirements for providing estimates of the performance of the units. I have no comments on R5, However, I have the following comment on R4. We agree with the intent of the requirement, but believe that more specificity in what is required in the written response is necessary. As written it could be argued that a simple response from the Generator Owner indicating they received the inquiry was sufficient. Suggest adding detail similar to that included in MOD-026, Requirement 3 that identifies what the response must contain.
For the WECC variance we would need a revised Attachment 1 that also shows the WECC No Trip Zone or an additional Attachment to illustrate the WECC variance No Trip Zone. WECC also requires modified language to R1 and the parts 1.1-1.5 to reflect the WECC variance. Requirements R5 and R6 will need to be modified to identify the appropriate Attachment for the WECC variance.
Individual
Kathleen Goodman
ISO New England Inc.
Yes
Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These

generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? The applicability criteria in this standard should be the same as the registry requirements.
Yes
Yes
This standard may lead Generator Owners to violate another NERC Standard; this standard implies in requirement R4 along with footnote 6 that Generator Owners could have 180 days to notify its Transmission Planner that an AVR status has changed. The VAR standards require notification within 30 minutes of a change in AVR status. Requirement R4 is also a direct violation of the ISO/FERC Tariff Section I.3.9 that requires generators to provide information prior to making material changes to equipment characteristics. Allowing generators to make changes such as these without prior review represents a significant reliability concern. MOD 26 needs to clearly state that non-proprietary models need to be provided by Generator Owners, otherwise a major reason (NERC MMG) for model collection will be undermined. As written, the intent of requirement R2.1.1 is unclear. How are stabilizers and excitation limiters to be addressed? How large does the voltage excursion need to be? This requirement needs to be made much more specific. With respect to requirement R1, the standard should allow user models to be provided. The second bullet point implies that models would only be allowed from a list of standard models. User written models may provide more accurate representations of actual equipment installations. However, these models cannot be proprietary and must be able to be distributed. In requirement R5.2 bullet 1 – generator owners should not be providing generic model data. In requirement R5.2 bullet 2 – what constitutes a “walk down” of the equipment? Suggest replacing with “Updating parameters based on actual field verification of equipment settings.” This standard should indicate what constitutes the excitation system and should indicate that it includes a power system stabilizer and limiters. This standard addresses existing generators, but should also address new generators. In regard to the Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas with very little verification for up to ten years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within it’s area.
No
The term “system voltage” is unclear as to where it is measured. Attachment 2 shows the curve based on voltage at the Point of Interconnection, yet R2.1 refers to voltage at the generator terminals. ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the “Point of Interconnection–Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. The time duration curve shown in Attachment 2 will need to modified to be consistent with this range for the times at and beyond 600 seconds to be consistent with this change.
Yes
Yes
The RC/PC/TOP/TP functional entities provide for a wide-area view of the transmission system and its operating limitations. These entities need accurate generator characteristics in order to correctly plan the system and to operate it within known limits.
Yes
ISO-NE has frequency data from all generators operating within the New England footprint demonstrating, with the exception of certain nuclear plants and some smaller and very old generating units, that all generators can operate to meet the under-frequency curve depicted by PRC-024 – Attachement 1, and, in fact, can and do meet our more stringent underfrequency requirements. Within the NPCC Region existing requirements for generators have been in place for many years that are more stringent than the underfrequency curve shown here. The NPCC more stringent requirements have been shown by studies to be necessary to support a viable automatic unferfrequency load shedding program. It is our position that generators within NPCC will be required

to continue meeting these more stringent requirements independent of the approval of PRC-024-2. New generating units should meet all the PRC-024-2 requirements at the time of their interconnection or in-service date. No special implementation plan should be afforded these units beyond the regulatory approval date of the standard.
Yes
Although the time duration is acceptable ISO-NE does not agree with the band shown. See our comments on Question 1, above.
Yes
Comments are provided by ISO-NE on the following requirements: R2.1. This requirement specifies when operating (within the band specified) of rated terminal voltage (VT) and during the transmission system operating conditions defined in PRC-024 Attachment 2 .... ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the “Point of Interconnection–Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. as suggested in our comments on Question 1 above R2.1.1 infers that the standard is to base the voltage relay settings on actual fault clearing times. The standard should be 9 cycles. As the system changes, clearing times may change and then problems with an existing generator who has set its relays to the actual clearing times may be an issue. Changing this requirement would also require a change in the curve shown in Attachment 2. If this comment is ignored, as an alternative ISO-NE suggests that R2.1.1 be modified to state, “For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, plus margin, not to exceed 9 cycles.” This is suggested to direct the setting of relays in a manner that will prevent a relay race that could trip the generator sooner than the actual fault clearing time. R2.1.3 appears to provide a way to get around the intent of the standard. If a generator cannot meet the requirements of the standard, they could put in an SPS to trip the generator and avoid meeting the intent of the standard. This has the potential to lead to a proliferation of SPSs. Notwithstanding the concern over R 2.1.3, R2.1.3 and R2.1.4 should be rewritten as follows: 2.1.3. If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relays to trip the generator even if [voltage is] in the “no trip zone” in PRC-024 Attachment 2 is acceptable [provided that the voltages will not enter the trip zone for criteria faults that do not initiate the SPS or RAS]. 2.1.4. If clearing a system fault necessitates disconnecting a generator, then setting relays to trip the generator even if operating [voltage is]within the “no trip zone” specified in PRC-024 Attachment 2 is acceptable. R3 is a significant concern. In the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the “No Trip Zone”, there is no requirement to correct the issue. Instead, the generator must only document the limitation. This completely undermines the intent of this standard. There is no point to setting undervoltage relays to meet the curve if other equipment is still going to trip the plant. R5 appears similar to R3 in that the generator is only required to document if it trips in the “No Trip Zone”, rather than correct the issue. Exceptions in 6.1.1 and 6.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024-2 without exception. In general, R6 and sub-requirements R6.1 through R6.7 introduce a number of conditions and exceptions for new units that are unnecessary and cumbersome to monitor. Some of them represent common sense conditions, such that if they were to occur, an auditor would be able to deem the entity to be in compliance since it is not posiible to comply with the letter of the requirement. However, there are many more cases that could be listed and you will never capture all possibilities here. Overall R6.1 through R6.7 should be deleted. As the system changes, the requirements will change. The machine should be properly designed upon installation to allow the necessary flexibility in the development of the transmission system over time.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Yes

Yes
Yes. There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Yes
MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES voltage response – and have already the recording equipment needed to validate performance.
No
Ingleside Cogeneration LP agrees that the continuous frequency specification is unambiguous and reasonable. However, the voltage operating specification needs to tie directly to the Transmission Operator's voltage or Reactive Power schedule developed in compliance with VAR-001. We believe this was the drafting team's intent, but the definition does not clearly indicate that this is the case.
No
Requirement R1 from Ingleside Cogeneration's perspective could lead to a double-infraction for the same incident. For example a single improper relay operation for an underfrequency transient would lead to a violation of both R1.2 and R1.3. It should be sufficient to specify that relays must be set in conformance with the off-frequency excursions provided in PRC-024 Attachment 1. Also, there must be some logical limit to the Hz/Second ride-through threshold specified in R1.5. As the requirement is written, even a large-magnitude frequency transient must not cause relays to operate as long as the frequency rate of change is slow. If for example, the interconnection frequency dropped to 55 Hz at a rate lower than 2.5 Hz/Second, R1.5 seems to require that the generator would remain connected to the BES. For the record, R2 seems to be more logically constructed – and lists reasonable exceptions to voltage relay settings. Ingleside Cogeneration LP recommends the drafting team to take a similar approach on R1.
No
Ingleside Cogeneration LP assumes this question actually applies to Requirement R5. It is not clear what extra reliability information will be provided to Transmission Planners as long as Generator Owners confirm that their voltage and frequency settings comply with the performance curves in the attachments. It may be valid to require an estimate of performance if the GO identifies a limitation as allowed under R3. Otherwise, the TP should assume generator relays will operate if the magnitude and duration thresholds defined in the attachments are exceeded.
Yes
Ingleside Cogeneration LP assumes this question actually applies to Requirement R6. The frequency and voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view.
Yes
The voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view. Existing facilities that cannot meet this specification must be able to document an equipment limitation as allowed in R3.
No
Individual
Brad Jones
Luminant Energy
No
I am not aware of any other generation configurations/types that should be covered in the Applicability portion.
Yes

Yes
No
No
The frequency is acceptable but the voltage band is confusing. The generator operating range is +/-5% from rated at full load. Luminant recommends that the voltage excursion be referenced to generator rated voltage.
No
Recommended that in the Footnote and in R1 indicate generator protective relaying.
No
Note: This appears to be dealing with R5 and not R4. R5 Because of the requirement under R5.3 (identification for basis for estimates of probability of staying on-line, etc), the study would take considerable time to compile. I would recommend that the generator owner be provided 90 calendar days rather that the suggested 30 to submit the results. R5.1 It appears that a frequency and voltage excursion must occur at the same time with the estimated time duration that the unit will remain connected. Was it intended that the "and" be an "or"? Would LVRT dovetail into relay loadability for stressed conditions for low voltage conditions between 45 and 90%? (Generator relay loadability is evaluated at 85% (PRC-023-2).) R5.3 Luminant recommends removing this requirement.
No
Generating units placed in service prior to this standard normally have 30+ years lifespan. During the life span, components targeted for LVRT will experience loss of life (time in use, number of operations, environment, etc) which could result in a failure of an LVRT event at the point of interconnection. Because a study may not be able to locate every component, an increase in reliability or the ability of the plant to ride through a low voltage condition could never be guaranteed above its current level. The same issue exist for new units. If the plant was designed to maintain LVRT conditions, there is no guarantee that the plant's ability to ride through low voltage conditions can be maintained during its life span.
No
The LVRT chart should only be limited by values pertaining to a system fault condition as a result of primary and backup transmission line relaying trip times (usually 0-30 cycles)
Yes
Luminant still believes that the standard should be directed to generator protective relaying only.
Individual
Patrick Farrell
Southern California Edison Company
No
Yes
Yes
Yes
SCE believes that the Section 4.2.4 of the Applicability Section should be revised to read "Any technically justified unit requested by the Transmission Planner." We believe that the Transmission Planner is the appropriate functional entity for this role. In addition, SCE believes that Requirement 1 should be revised to allow the Transmission Planner a full 60 days in which to provide the information to the Generator Owner. At various times, Transmission Planners may be inundated with such requests from Generator Owners and may require the extra time in which to respond.

Individual
Kirit Shah
Ameren
No
Yes
Yes
Agree that there are relatively few synchronous condensers installed on the system. Including these devices with other dynamic reactive devices such as SVC's and STATCOMs, rather than in this standard, appears to be a good approach.
Yes
Our comments/concerns are : 1)The wording for Requirement 2.1.4 should be changed to read "Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator". Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment. 2)In Requirement R5, the term "technically justified request" needs to be clarified. 3)In Requirement R2.1.3, it should be clarified that "rotational inertia" should include all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself. 4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included. 5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators. 6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy. 7)The draft uses the term "Point of Interconnection" in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition. 8)Footnote 6 should be a set of sub-requirements for R4. 9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard. 10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote – it's too important in determining which generators must comply.
No
Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary.
Yes
No
Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable
No
Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine with any reasonable accuracy where auxiliary motors would stall and trip off, or contactors drop out.
No
This 90% and 110% ride through times should be longer to handle contingency periods of high voltage during light load conditions or periods where large VAr resources are lost during peak loads. Per our Transmission Planning department high voltages of 110% have been experienced for up to 8hrs.
Yes

1)Comments: Requirement R1.5 is unclear. Are the relays not allowed to trip regardless of frequency if the rate of change is less than 2.5 Hz/sec. If so, the existing generator relays don't have the capability to block for this condition. It would seem undesirable to block for this condition and risk damage to generation. 2)R2.1.3 needs to be more specific. With multiple outlet lines, generators may only be tripped for certain lines or breaker failure conditions. Generators would only be allowed to trip in the "no trip zone" for the specific conditions of the SPS or RAS schemes? 3)R6.2 why are smaller generators allowed to trip 10% of their units? Is this fair to large generators? 4)Do all the requirements of PRC-024-1 apply to all the auxiliary systems, or just the generating unit protection systems? This needs to be made clear for compliance. If applying to all auxiliary systems, guidance will need to be provided on how to meet these standards. 5)For R2 and R6, if clearing a transmission line outlet end of line fault with zone-2 timing exceeds the requirements of Attachment #2, which should be designed for. Does transmission line relays need to be designed to provide performance of Attachment #2 for newly installed facilities?
Group
Southern Company
Antonio Grayson
No
Yes
Yes
It is possible that the owners of the transmission system dynamic reactive devices (such as synchronous condensers, SVCs, STATCOMs, etc) may not be a NERC registered entity at all. Moreover, it is highly inappropriate to just add equipment not mentioned in the original SAR to the standard. It makes more sense, as SDT suggested, to have a separate SAR to address those transmission system dynamic reactive devices.
Yes
1) We question how field tests can be performed on aggregation based facilities. We recommend removing the requirement for developing models for the aggregation of units < 20 MVA for conventional units. 2) Isn't R2.1.3 already required of the GO in MOD-012 (dynamic data on generators) 3) The timing of R5 requirement (90 days) seems to contradict with the schedule for modeling in Attachment 1 (1 1/2 years) for PC initiated model reviews. 4) The background section indicates that the PC can request a unit not in the applicability scope (page 2, last paragraph), but R5 doesn’t say this. The wording on R5 indicates that the PC can request a review of an existing model. 5) Attachment 1 is difficult to use. Please cross reference the requirement that goes with each row of the periodicity table Attachment 1. Please add row numbers to the table. Please use column 1 to briefly label the conditions that controls the applibility of the row (for example - the row including the exceptions could be labeled SISTER UNITS) 6) It is suggested to review the order in which the requirements are currently numbered. The current R3 seems to be out of place (should occur after the requirement that is currently R6). This will more closely match the flow of how the process will work. 7) VSL for R1 needs work – the requirement specifies 30 days – the VSL doesn’t count it tardy until 90 days. 8) The Sister concept needs to be mentioned in the applicability section 9) The exception rule in Attachment 1 should include Sister units at different geographic sites in addition to those at the same site. 10) The exception rule in Attachment 1 should not be limited to 350MVA – if units are identical, then the sister concept should apply. 11) The first bullet of R1 needs to make "model" plural ("models") for the grammer to be correct. 12) As the requirement of R4 is not a response to a request, we suggest changing the wording of the text in M4 from "show that it provided a written response (...) submitted within 180" to "show that it submitted communication (...) within 180", where (...) is shown to indicate no change to the parenthetical element. 13) As requirement R6 is an evaluation of the verified model by the TP, we suggest changing the wording of the text in R6 from "show that it provided a written response" to "show that it provided an evaulation of the submitted model".
Yes
Yes

1) The footnote is clear, however, the exact meaning of the phrase "non-protective system equipment" limitation in R1 and R2 is not clear. Does this exclude any equipment limitation that is protected by a protective relay? Does this allow tripping using protective relays that are protecting a turbine from underfrequency conditions or a generator or transformer from excessive volts-per-hertz conditions? We feel that a fundamental tenant of reliability includes adequately protecting generating plant equipment from detrimental conditions - a generator owner needs to be allowed to protect its equipment from possible damaging consequences of off-nominal voltage and frequency. 2) We believe examples of “non-protection system equipment” include, but are not limited to, turbine generators, transformers, feed pump systems/controls, boiler control systems, reactor protection systems, emergency diesel generators, AC motors, pumps, fans, AC motor contactors, auxiliary relays, etc. 3) Nuclear stations have an approved Setpoint Methodology which governs the process of determining and documenting setpoints for the equipment at that station. This methodology will incorporate some margin between the expected operating condition and setpoint actuation to help ensure proper operation of the unit but provide the necessary protection as well. How was this considered in the development of this standard?
No
1) This Question is for R5, not R4. 2) We disagree with this approach due to the uncertainty about how to estimate the performance. The detailed dynamic analysis required to make an estimate of a specific units performance is not reasonable to require. The voltage excursion profile needed for an evaluation is that voltage present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. The protective relays and control equipment susceptible to high/low voltage excursions are located on the low voltage side of the generator step up transformer. Does agreeing with the approach mean the philosophical desire to provide the TP with information or mean agreement with the requirement to provide estimations of the voltage excursion ride-through ability? We agree with the philosophical mantra, but we are not sure if a conclusive determination of a unit ride-through capability is possible. Generation Owners need a curve from Transmission that is referenced to the lowside since that is where the relays/equipment are located. 3) Does “estimate of that unit’s performance” only include the estimated time duration of 5.1 and probability of remaining connected in 5.2? Or, does it also include things like the estimated generator terminal voltage, MW, MVars, etc. for the duration of the frequency or voltage excursion? This needs to be clear. 4) The 30 days requirement is much too short. There are a large number of systems and components that would first have to be identified as susceptible to responding to these extreme conditions (especially the voltage conditions). Each of these would then require evaluation, including dynamic analysis for systems and components that respond dynamically over these relatively long time periods. This amounts to major study work on a single unit, much less over many units of many different system configurations and designs having equipment of many different manufacturers and vintages. Also, dynamic studies require accurate system and equipment models to produce valid results and the effort to establish accurate models is no simple task.
No
1) This question is for R6, not R5. 2) We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers. 3) Even if this can be achieved, it will require significant changes in the power plant industry. This will include major changes to plant system and equipment design standards (both U.S. and International). This alone will take years to accomplish. Then, manufacturers will have to design, build, and test plant systems and equipment to meet the new requirements. It is impractical to expect a new plant that can meet both the frequency and voltage requirements to be built in less than 10 years after R6 is imposed.
No
1) The 600 seconds for +/- 10% voltage excursion is excessive. GE has published recommended generator permissible V/Hz settings for a stairstep protective solutions of not allowing > 118% V/Hz to exist longer than 2 seconds, and not allowing > 110% V/Hz to exist longer than 45 seconds. The HVRT curve requires allowing 110% V/Hz for 10 minutes, which is much longer. 2) Generators need a generator side excursion curve to even see if this is feasible. 3) We believe a detailed study needs to

be conducted by the industry for typical power plant designs to help determine the feasibility of power plants being able to ride through these extreme voltage conditions. We believe this study will demonstrate that this will not be possible without major re-design of power plant systems and components.
Yes
1) It is recommended to rephrase R4 so that the requirement (shall statement) is first and the conditions (within x of receiving a request) is second as follows: "The Generator Owner shall provide a written response within 90 calendar days of receipt of a written inquiry from the RC, PC, TOP, or TP regarding an equipment limitation identified in accordance with Requirement R3." More response time than 90 days is needed for cases were a written inquiry is given to a GO (with a very large number of units) for all units in one request. 2) We believe that the condition specified in R6.2 should be limited to PV plants and wind farms? 3) Since Requirement R6 provides exceptions to the requirement (6.3 thru 6.7) these exceptions need to be mentioned in Measure M6. (add "unless one of the exceptions 6.3-6.7 apply" to the end of the sentence.) 4) Employing new grid frequency and voltage ride-through requirements may impact the licensing and design basis of nuclear facilities. NUC-001-1 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown. This is achieved through development of Nuclear Plant Interface Requirements (NPLRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities. The NPLRs are requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance or transient condition is important. It is essential that this process be followed closely in attempting to apply new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant's licensing and design basis. It is fundamental that the safety of nuclear power plants take precedence. 5) R3 states "each" non-protection system equipment limitation where R1 and R2 say "a". Is there a reason for this difference? The feasibility of fully analyzing an existing plant to determine this is extremely questionable. There is no doubt that the cost would be horrendous. 6) We suggest modifying Footnote 2 - add "being built to a completed certified standard design" to this list. If the industry is going to move forward in utilizing standard plant designs to reduce cost and expedite getting plants built, the certified design must be acknowledged. If the equipment to meet this standard can be obtained, which is doubtful, the only way to reasonably attempt to have a design that meets it is to start with these requirements as design criteria at the very beginning. To place requirements such as this on completed standard designs would destroy the use of that concept. 7) The approval of this standard as written will have extreme effects on the construction and operation of generating units which could also affect safety and availability. It would greatly increase the cost and schedule for building generation units and impose a huge cost on existing ones. We believe those developing this reliability standard should be sensitive to such concerns and give them consideration. Has this been done? Is it fully documented and available for review by the industry impacted by the proposal?
Individual
Thad Ness
American Electric Power
No
Yes
AEP is not aware of any omissions from the prior draft due to the re-formatting of the standard.
Yes
Yes
Standard models may not be available for wind units and wind facilities (which appear to be within scope), particularly aggregate reactive and frequency response controls at the farm level. As a result, it might be difficult to obtain and provide such information.

Yes
Where these definitions appear to be referenced in the standard (R5 and R6), they seem to be at odds with Attachments 1 and 2. Either the attachments should be used and remove the definitions, or instead, the definitions should be used and remove the references to the attachments in R5.1 and R5.2 and R6. We recommend removing the definition of "Frequency Excursion" and retaining Attachment 1 subject to our comments given elsewhere in this document. We recommend keeping the "Voltage Excursion" definition and eliminating Attachment 2 based on our comments elsewhere in our response.
Yes
Although the footnote is worded somewhat awkwardly, it is clear that a Generator Owner is not required to have protective relaying installed or set for these functions. Suggest using "Generator Owners are not required to have… installed or activated on their units".
Yes
A Generator Owner should only be required to report known limitations that might cause their unit to trip. As written, one could be in violation of the standard for some unknown limitation which might exist and that might only be known after an event has occurred. This question seems unrelated to R4 which states the time provided to respond to a written request for information. Rather, it seems to be related instead to R3 or R5.
No
This question references R5, but we believe the team intended to reference R6. The requirement for new units and plants to not trip within the envelope of Attachment 1 is reasonable; the design of turbines involves some off-nominal frequency versus accumulated time criteria and Attachment 1 is being proposed in view of existing design criteria of major manufacturers. While the Standards team has proposed this in view of OEM design criteria, it would be beneficial to obtain input from the OEMs to learn what issues if any they have with this proposal and what changes and/or incremental costs could be incurred to meet the Standard for new or existing generators. The design and ability of auxiliary systems to meet the requirements outlined in Attachment 1 will require review. To not trip within the envelope of the Attachment 2 Voltage Ride-through Time Duration Curves is another matter. No requirement such as this has ever been imposed on generating units in the past and we question the need for it now. The appearance of such graphs seems to have been in response to the performance of wind farms that tripped off-line by protective relays when disturbances occurred on the transmission system. The Attachment 2 VRT curve may thus be an appropriate requirement for wind turbine generators. The applicability to conventional generation, however, is questionable. Further, the curve and the supplemental tables (curve data points) seem to be at odds with the language of R2, e.g. R2.1.1 which states for three-phase transmission system zone 1 faults with Normal Clearing, interpreted to mean as little as 3 cycles up to and not to exceed 9 cycles depending on the transmission relay practice and transmission voltage application. Specific comments on and objections to R6-Attachment 2 are as follows: (1) It is not at all clear that a conventional generating unit could maintain synchronism during POI voltage events within the envelope of Attachment 2. The standard needs to explicitly state that Attachment 2 is not a requirement to maintain synchronism (which is already covered by TPL standards). This point must be made clear within either the text of the requirement or else in a footnote, not just the comment form. (2) Should the SDT retain this requirement, it would be advisable to limit the scope of Attachment 2 in R6 to generator over- and under-voltage relay settings and any unit auxiliary equipment over- and under-voltage protection whose operation could lead to the loss of the unit. However, it is also not at all clear whether auxiliary systems could be designed to withstand voltage disturbances within the envelope of Attachment 2. Further complicating auxiliary systems ride-through, while such a graph may be appropriate for wind farms, it is not appropriate for conventional synchronous generators that have a substantial capability to control the voltage they are subjected to during a system disturbance (unlike most wind farms) and whose critical auxiliary systems are usually (and should be) served from the generator bus (low side of GSU) and are thus insulated to some extent from what may happen on the transmission system. A more appropriate requirement for conventional generation would be to require an automatic over-excitation limiting (OEL) function that is coordinated with over-excitation protection. However, we believe OELs are now standard equipment among excitation equipment suppliers and should not need to be required in a standard. (3) It would be impractical, if not impossible, to test or otherwise verify generator ride-through for POI voltage disturbances within the envelope of Attachment 2. In view of the above considerations, and in the interest of treating all generation types

equitably, we believe a more appropriate approach to generator voltage ride-through would be deference to TPL standards for the types of transmission system disturbances where stability needs to be maintained. This has always been an acceptable criterion for conventional generation ride-through in the past. It is not stated in these terms in this proposed standard and independent review of a random sample of units could demonstrate the units may not meet this R6-Attachment 2 performance requirement though they would meet R2.1.1 and TPL standard requirements. It would be beneficial to state somewhere that any fault or other disturbance on the transmission system for which a conventional generator is expected to survive, a wind farm must also survive without tripping. (A statement such as that may be out of place in this standard and perhaps ought rather to have been included in the new TPL-001-1.) The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied. Therefore, for the purposes of the R6 performance requirement, we believe that reference to Attachment 2 should be removed.
No
We agree that a new generating unit reasonably could be required to ride-though 90 percent or 110 percent voltage at the point of interconnection for 600 seconds at nominal frequency. However, this does not take away from the concerns expressed in response to Q4.
Yes
The second point under R3 causes the limitation to expire with rating increases. Is a 10 percent or more rating increase a realistic scenario and common enough to justify attention? 10 percent seems arbitrary and this provision could pose a hindrance to rating increases that may supply other reliability benefits. It may be advisable to remove this point. We believe that R2.1.4 must not allow relay settings to trip a generator within the no-trip zone for other system events that would not disconnect the generator. The phrase "generating plant or Facility" is used in R2, R3, R5 and R6, but not R1.
Individual
Larry Grimm
Texas Reliability Entity
Yes
(1) The implementation period in this standard is far too long. It is unreasonable to allow 11 years for a GO to provide a verified model for 50% of its generation capacity. All generation should comply with Requirement 2 within 3-5 years. (2) The periods allowed for providing correction of identified model deficiencies and updates for system changes are too long. It appears (from Attachment 1) that a GO has almost 2 years to provide a corrected verified model after a request from a TP or an equipment change (per Requirements R3, R4 and R5). This work should be completed within one year to ensure accurate system modeling. (3) It is unclear exactly what is required by Attachment 1, and how the material in the attachment relates to the Requirements. The Attachment appears to contain additional requirements. We suggest moving the required actions described in Attachment 1 into the applicable Requirements, such as the requirements and time periods for recording responses and providing new information to the TP. (4) It is unclear what the 10 and 11 year periods/cycles referenced in the first two rows of Attachment 1 refer to. This needs to be clearly explained somewhere. (5) It is our understanding that this standard is intended to require re-verification of models at least every 10 years, but there is no requirement that clearly sets forth any re-verification requirement or period. (6) Requirement 6 requires the TP to determine if a model is “usable” based only on whether the model is functional, omitting any consideration of whether the model is reasonably accurate. An incorrect model could satisfy 6.1, 6.2 and 6.3. We suggest adding an R6.4 relating to whether the model is reasonably accurate, i.e., whether it reflects actual unit performance. (7) In 4.2.3, in the first bullet, “with rating greater than” should be changed to “at greater than,” which is clearer and consistent with the parallel descriptions in neighboring sections. (8) In the “Consideration for Early Compliance” section, first bullet, “applicable regional entity policies” should be changed to “applicable region policies.” In our region, and perhaps others, there are applicable policies, but they are not “regional entity policies.” (9) Several very informal terms are used that should be replaced with more specific language, such as “walk down” (R5.2) and “local grid codes” (Attachment 1). In R6.2, the term

“negligible transients” in too indefinite and should be replaced by a more objective measure. (10) The terms “unit,” “plant,” and “facility” are used inconsistently in the draft. (11) M4 refers to a “request” and a “response,” but there is no request/response interchange in the associated Requirement R4.
Yes
In the ERCOT Interconnection (ERCOT) there are well-established generator under-frequency relay settings (ERCOT Nodal Operating Guides 2.6.2) that are more stringent than those proposed in this standard. ERCOT also has existing low/high-voltage ride-through requirements (ERCOT Nodal Operating Guides 2.9(2)) that are less stringent than those proposed in the standard. We would prefer to include the existing ERCOT parameters in this standard to apply within the ERCOT Region, rather than having different ERCOT and NERC requirements. We suggest that the drafting team consider adding ERCOT-specific parameters in Attachments 1 and 2, matching the existing ERCOT Nodal Operating Guide requirements, in addition to the stated parameters for the other interconnections.
Group
Electric Market Policy
Mike Garton
No
Yes
Yes
Dominion suggests: MOD-026 Section 4.2.4 needs to be removed to be consistent with other standards. MOD-026 Section 2.1.1 “match” should be changed to approximate. The model will never exactly match. MOD-026 Section 2.1.6 remove “structure”. MOD-026 R3 bullet 3 “match” should be changed to approximate. The model will never exactly match. MOD-026 Attachment 1 title is missing “M”. MOD-026 Attachment 1 column “Condition” replace eleven and ten with “eleventh” and “tenth”. MOD-026 Section 4: Applicability should spell out testing exceptions.
Yes
No
The question is confusing because of the phrase “set for these functions.” The language in Requirements R1 and R2 as well as footnote 1 suggest that GOs are not required to have the specific relays “installed or activated on its units. If however, the relays are activated then they are required to be “set” pursuant to the standard.
No
Requirement R4 seems to be duplicative of the obligation to notify the same entities under Requirement R3. Perhaps the language in R4 could be clarified to indicate the distinction.
No
This appears to be a design question that presumably the standard drafting team researched and quantified to provide a basis in framing the curves of Attachment 1 and Attachment 2. If this is true, more documentation should be provided to the ballot body.
Yes
Yes
Dominion suggests the following: Section 3 should capitalize “frequency and voltage excursions”, as they are defined terms. Do not understand R3 bullets. How does increasing your units rating by

≥10% change this? Attachment 2 does not match ±5 voltage schedule per the definition of Voltage Excursion. This curve is not possible. R6 grants new generators exceptions. Where are the exceptions for existing generators? This standard only applies to frequency and voltage excursions within the defined limits. The attachments and requirements go outside of this bound placing much more stringent criteria on the operation of the units. These more stringent criteria may not be possible and should be removed from the standard to align with the definition of applicability. The last sentence of the associated Implementation Plan is confusing. Suggest revising to read: “Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.”
Group
Dynamics Review Subcommittee
Joe Spencer - SERC staff
No
Yes
Yes
It is good strategy to include synchronous condensers with other dynamic reactive devices as they all fall under the same category – providing dynamic reactive support.
Yes
R2: The wording for Part 2.1.4 makes it seem that the required model structure and data only applies to the voltage regulator portion of the excitation system. The DRS recommends that R 2.1.4 be reworded to: "Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator." R5: A "technically justified request" needs to be clarified. We suggest using words similar to those used in the slides associated with this project: "A technical justification that demonstrates, through simulation and/or measured response, that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response." R2.1.3 : The DRS recommends a clarification to “rotational inertia.” Please consider the following wording: "Generator (or plant equivalent) model structure and data (such as reactance, time constants, saturation factors, rotational inertia (including all rotating components), or equivalent data)."
No
Exceedance implies that the frequency is greater than desired frequency. Since the intent is to identify frequencies greater or less than a specified amount from the desired frequency, replacing the word “exceedance” with “deviation” and “beyond” with “outside” seems more appropriate.
No
It is unclear how an entity can have protective relaying settings for new units. Since "existing units" covers units under construction as specified in footnote 2, "new" implies planned units and thus the associated relaying would also be "planned" not "existing." It appears the word “new” should be deleted from sentence one of R1 and sentence one of R2.
Yes
We assume this pertains to R5 not R4. 30 days is probably not enough time for a GO to determine a suitable estimate. We recommend 90 days.
Yes
Requirement R6 not R5.
Yes
While we agree, a technical basis for this 600 secs. duration (and each breakpoint) would be helpful.
Yes
Under R5, Severe VSL Requirement 55 should be Requirement 5. R7 refers to generator protection trip settings as "specified" in R1 & R2. Settings are not specified in R1 & R2. We recommend using "referred to" instead of "as specified." “The comments expressed herein represent a consensus of the views of the above named members of the [insert the full name of the group] only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Group

LG&E and KU Energy
Brent Ingebrigtson
Yes
Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. LG&E and KU Energy suggests tha the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.
Yes
No
Comments: LG&E and KU Energy recommends the wording be changed for R1/R2 to “Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following…” Or, change from “Each GO” to “GO’s that have frequency and voltage protection functions activated to trip a new/existing generation unit.”
No
: LG&E and KU Energy agrees with the approach but recommends 60 days. Moreover, this appears to be R5, not R4.
Yes
: This appears to be R6, not R5 and should be achievable for new units.
No
LG&E and KU Energy agrees with the SERC Generation Subcommittee and proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Yes
LG&E and KU Energy would prefer to have 60 calendar days on
Individual
Anthony Jablonski
RFC
Yes
Yes
Yes
Yes
RFC offers the following suggestions regarding the Violation Severity Levels: 1. VSL for R1 – There is a disconnect between the date listed in the VSLs and requirement. The timeframe for the “Lower” VSL starts at 90 calendar days though the requirement states “within 30 calendar days”. Where does an entity fall if they provide instructions 45 calendar days of receiving the request? Based on the current VSLs, they would not even fall under the “Lower” VSL. 2. VSL for R3 – To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R3.” Or conversely remove this language from the “Severe” VSL and replace with “R3”. 3. VSL for R4 – To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R4.” Or conversely remove this language from the “Severe” VSL and replace with “R4”. 4. VSL for R5 - To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R5.” Or conversely remove this language from the “Severe” VSL and replace with “R5”. 5. VSLs for R6 - To be

consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R6.” Or conversely remove this language from the “Severe” VSL and replace with “R6”.
Yes
Yes
Yes
Yes
For R5, Part 5.1 and 5.2 – suggest adding the word “PRC-024” in front of “Attachment 2” in the last line of the respected Parts.
Yes
Yes
For R3, add the word “generating” in front of the word “Facility” to be consistent with other requirements. The followoing are reccomendations related to the Violation Severity Levels: 1. VSL for R1 – a. The VSL should start off with the following language to be consistent with the language within the requirement: “The Generator Owner that has frequency protective relaying activated to trip its new or existing generating unit failed to…” b. Since there are a number of Parts associated with R1, the SDT may want to consider gradating the VSL rather than making it Binary. 2. VSLs for R2 – a. The VSL should start off with the following language to be consistent with the language within the requirement: “Generator Owner that has voltage protective relaying activated to trip its new or existing unit or generating plant or Facility failed to…” b. There is no reference to any of the Part numbers for R2. Suggest adding references to the Parts to the VSL or since there are a number of Parts associated with R2, the SDT may want to consider gradating the VSL rather than making it Binary. 3. VSLs for R3 a. Suggest not using the language “…prevents compliance with Requirement R1 or R2…” since it is not consistent with the language of the requirement. Suggest stating: “… prevents the Generator Owner from meeting the criteria in Requirement R1 or R2…” 4. VSLs for R5 a. Fix the typo in the “Severe” VSL. Change “R55” to “R5” 5. VSLs for R6 a. The first VSL under the “Severe” suggest referencing “Attachment 1” rather than “Requirement 6.” This will make it consistent with the other “Severe” VSL. b. Suggest adding another VSL which references the GO not following the conditions and exceptions in Parts 6.1 through 6.7. As written, there is currently no reference to the Parts.
Group
FirstEnergy
Sam Ciccone
No
Yes
Yes
Yes
FirstEnergy provides the following additional comments and suggestions: 1. Unfortunately as written this standard may require Generator Owners to purchase software to properly analyze voltage excursions to verify their models. This level of expertise historically existed with the TO/TOP, not the Generator. It will be very difficult for the Generators to develop and maintain this expertise for a verification that will only be run once every 10 years. Also, if additional instrumentation is needed to capture this data, nuclear fleets may be challenged to ensure at least 30% of their applicable units will comply with R2 based on refuel outage schedules. 2. Applicability Section 4.2.4 – We do not agree with the Planning Coordinator being able to include additional units. Even though the standard says that the PC would have to show technical justification, it should not be left to their discretion to

add an entity's unit as applicable. A regional entity is the only ultimate authority that can make this decision and the PC should go through its Regional Entity to prove this justification. We suggest removing this section. Furthermore, it states that the technical justification would need to be verified. It is not clear who would make this judgment on the validity of the justification. 3. We are not clear as to what the standard is referring to when it mentions "volt/var control". 4. In requirement 2.1.1, of R2 it states "2.1.1. Documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance." The SDT should specify the magnitude of the voltage excursion referenced in this section. 5. In the SDT notes they make reference to allowance being given for identical (Sister) units but I did not see it anywhere in the standard. Can Generator Owners take credit for Sister units when supplying the model verification? 6. As a general note, the first draft of this standard was reviewed by industry over 2 years ago. It seems like a long time between drafts to expect the industry to review and vote on a standard given that there may be several new personnel in a company that are new to compliance. I would have hoped the team came out with only a comment period at this time. 7. Attachment 1 - General Comment – "M" is missing from title of attachment "OD-026 Attachment. Also. We assume that the mentioned "voltage excursion" is in reference to the proposed definition found in the proposed PRC-024-1. If so, it should be capitalized and added to the front of the standard and balloted with the standard.
Yes
Yes
Although we agree with the requirement, we noticed that the VRF and Time Horizon is missing for R4. We suggest a LOWER VRF and Long-term Planning Time Horizon.
No
Requirement R5 – It may not be feasible for the GO to provide this information in 30 days. We suggest allowing 90 days. Regarding 5.2 and the estimation of the probability, we are not clear as to what is required. The wording is confusing and cannot offer suggestions because we are not sure what the intent is. R5.1 – Some nuclear plants will not be able to run at 95% voltage indefinitely as required as that voltage is lower than each plant's Licensing Basis for degraded grid voltage. We ask that this standard include an exception for nuclear generators that allow them to report what % of grid voltage will force them into a Limiting Condition of Operation if that % voltage is higher than 95%.
Yes
FirstEnergy offers the following additional comments and suggestions: Requirement R3 – It is not clear how this requirement relates to the identified generator equipment limitations. Furthermore we are not clear what "continuous capacity rating" is referring to. We suggest the removal of the second bullet which states "the generator unit continuous capacity rating increases >= 10%". Requirement R3 – This standard does not account for the fact that nuclear plants have equipment other than the generator that potentially will trip the unit at frequencies/ voltages outside of the limits shown in Attachments 1 and 2. Nuclear plant voltage and frequency trip points are set to ensure safety equipment will operated as specified in the plant's License. The standard needs to allow nuclear generators the ability to specify if something other than the generator protective relays dictates where a unit will trip. Under 6.7 (exception) - A unit or generating plant or generating Facility may trip if the protective functions (such as out of step or loss of field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment. Maybe this section should include an exception for Volts/Hertz protection. General - The standard should state whether disturbances that include both frequency and voltage excursions are covered under the standard. For example, our Volts/Hertz protection trips in 45 seconds at 110%. The standard calls for a HVRT of 600 seconds at 110%. This current Volts/Hertz setting would not meet the standard.
Individual
Travis Metcalfe
Tacoma Power

Yes
Yes
No
Yes
Yes
Yes
No
The required voltage and frequency settings should be determined by the interconnecting entities regional off nominal voltage and frequency plans.
No
Group
PacifiCorp
Sandra Shaffer
No
Yes
Yes
Yes
Modeling wind generation without a developed generic model is a concern. If the generic models are not developed once the standard is effective are exceptions going to be made to accommodate this?
No
The definition for Voltage Excursion provided in the most recent draft of PRC-024-1 is closer to the definition of a voltage deviation. The Voltage Excursion definition should be modified to include a time duration component, e.g. “fast transition” of system voltage beyond the continuous operating band of ±5% of scheduled voltage. Otherwise, a very slow voltage transition could be considered a voltage excursion if it exceeded the voltage band, thereby missing the intent of and time frames set forth in Attachment 2. A similar comment is applicable for Frequency Excursion. A transition time duration is key to the definition of both Voltage Excursion and Frequency Excursion due to the significant impact that these parameters can have on a generating facility.
Yes
Yes
(R4 referenced in the question actually should refer to R5 in the standard)
No
There are going to be certain exceptions to new units or facilities being capable of staying on line under the listed circumstances just as there are current exemptions for existing facilities. Exceptions could be related to VFD (variable frequency drive) operation or motor operation at the plants, which would be true of both existing and new generating plants. There is also a possibility of overcurrent trips during these voltage conditions, tripping would not necessarily be limited to voltage or frequency relays. It would be difficult for Generator Owners to answer this question fully without a thorough

study of how the frequency and voltage excursions will impact generation loads. Generation protective relays do not typically base their protection on transmission system voltages at the point of interconnection.
No
In studying PRC-024 Attachment 2, PacifiCorp believes that the “high voltage duration” curve, which defines the upper edge of the no trip envelope by depicting a 1.10 pu voltage between 1 second and 600 seconds, may potentially conflict with the synchronous generator Inverse-Time V/HZ Relay with Fixed-Time Unit setting recommendations contained in IEEE Std C37-102. For example: At 110% V/Hz, the relay will trip in 291.6 seconds (within the PRC-024-1 No Trip Zone). Additionally, at 109% the setting would be at 1166.4 seconds. PacifiCorp requests that the Standards Drafting Team (“SDT”) further evaluate PRC-024 Attachment 2 to determine if an adjustment to the high voltage duration curve could eliminate this potential conflict.
Yes
In addition to the feedback noted above, the NO votes submitted by PacifiCorp are accompanied with the following comments: (1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: • R1.1.5 – PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. • R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. • R3 – This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. • R6 – The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditons within 95% and 105% of rated generator terminal voltage and during the transmission system conditions define in PRC-024 Attachment 2, with the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner’s study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner’s settings or the setting applicable to in PRC-024 Attachment 2. 2.1.3 Tripping a generator via If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping

a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the is acceptable in the “no trip zone” in PRC-024 Attachment 2 is acceptable. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable than setting relays to trip the generator even if operating within the “no trip zone” specified in PRC-024 Attachment 2 is acceptable. (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC’s Off-Nominal Frequency Load Shedding Plan (“WECC Coordinated Plan”), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. (5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. (6) PacifiCorp offers one comment on the Violation Severity Limits (“VSLs”) proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs. (7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a “one-size fits all” standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies.
Group
TVA - GO
David Thompson
No
Yes
Yes
No
No
TVA believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to “... exceedance of system voltage beyond the applicable voltage schedule
Yes
No

The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
No
The proposed bands would need to be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant designs and no concerns were identified. However, it is not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) have been and are normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)”as follows: a. Normal Conditions: ±5% Continuous Duration b. Emergency Conditions: ±10% not specified Duration These Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
No
TVA proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience.)
Yes
During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: • Important Existing nuclear plant settings are inside the published no-trip bands • How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. • Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No

Applicability to Smaller Units: The proposed standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some local areas. The applicable criterion should be the same as those used in the Compliance Registry. No capacity factor exemptions should be allowed without a technical justification. Also see section 4.2, footnote 2. This is a broad exemption, and as we saw recently during the continent-wide heat wave, almost all units within our control area were operating. The requirement is to test once every 10 years. This is not an excessively onerous requirement.
Yes
The inclusion of all reactive resources as BES Elements covered by a separate standard would be consistent with the current draft of the proposed Bulk Electric System (BES) Definition and Designations being proposed by the BES standard drafting team.
Yes
Requirement R5 – Please define the term “technically justified.” We recommend using wording similar to Comment form paragraph 8) in that definition: “[S]upply technical justification that demonstrates either a) the unit affects a stability limit, or b) the simulated unit response does not match a measured unit response (most likely captured during a system disturbance event).”
No
Requirement 1, paragraph 1.1 requires that units remain connected, 1.1. When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive. Yet the definitions of Frequency and Voltage Excursion could be misinterpreted to apply only to trips occurring when the frequency or voltage at the time of trip-out was outside the normal operating range. We do not believe that it was the intent of the drafting team to exempt units which might trip within the normal operating range during an event. Therefore, we propose to change the focus from Excursions outside a normal operating range to variations within and outside that normal operating range, out to specified limits (the operating envelope). We suggest that the term Frequency and Voltage Excursion be re-defined as variations follows: Frequency [delete “Excursion” add “Variation”] – an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] frequency within a planned continuous operating band, e.g., 60±0.5 Hertz, and beyond a planned continuous operating band to specified limits (Attachment 1). Voltage [delete “Excursion” add “Variation”] – an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] voltage within a planned continuous operating band, e.g., 0.95 to 1.00 per unit, and beyond a planned continuous operating band to specified limits (Attachment 2). This definition includes certain types of specified variations: (a) Operation within an allowable normal operating bands, such as voltage variations within an allowed ±5% of scheduled voltage, e.g. from 0.95 to 1.00 per unit. (b) Operation within a modified scheduled operating band voltage change, such as with the range around a scheduled nominal voltage reduction during a brown-out, where the allowed voltage operating band is intentionally reduced, and (c) Operation up to limits specified and/or referenced in MOD-026. For example, voltage variations either within or outside of the scheduled operating band of 0.95 to 1.05 per unit of nominal, e.g., a 328–362 kV operating band around a 345 kV scheduled nominal voltage. We propose to change the Purpose wording (and similar wording elsewhere) as follows: Purpose: Ensure generating units remain connected during frequency and voltage [delete “excursions” and add “variations”] and ensure expected generating unit performance during frequency and voltage [delete “excursions” and add “variations”] is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.
Yes
Yes
Yes
Yes

Yes
Requirement R3. – Delete the word “expires” and replace it with the words “documentation should be renewed” The underlying technical justification for this standard should be supported by a white paper similar to the document available at this link (AREVA PRC-24 White Paper Clean.doc): http://xa.yimg.com/kq/groups/28536519/188315025/name/AREVA%20PRC-24%20White%20Paper%20Clean.doc Requirement R3, bullet 1 allows for an exemption for existing plants subject to equipment failures until “the limitation [limiting equipment] is repaired or replaced.” Similar temporary exemption language should be incorporated in R6 for new units that experience equipment failure-related limitations. The drafting team may also wish to address a requirement for repair or replacement timeliness in both R3 and R6.
Group
Santee Cooper
Terry L. Blackwell
No
We’re not sure these definitions serve a useful purpose, since, later on in the standard, these excursions are defined by the curves in the attachments.
No
The sub-requirements of R2 could be read as prescribing exactly where you have to set this relaying. Often our relay set points originate with the OEM and are based on protecting the Generator and Turbine. The finalized curves that originate here should be used as a means to arrive at those settings, but, as long as the settings do not cause the relaying to operate for the ranges in the finalized curves, the requirements should be satisfied (It shouldn’t have to be stated that you can set them less stringent, if you can not have the relaying entirely).
No
It should be ascertained how and if the TP will use this in TPL-001 analysis. It will be unclear how to demonstrate compliance.
No
This appears to refer to R6. The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidence provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)”as follows: a. Normal Conditions: ±5% Continuous Duration b. Emergency Conditions: ±10% not specified Duration These Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilzed at power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.

No
The LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
No
Individual
Gary Chmiel
GE Energy
No
Yes
GE has no comment.
Yes
GE has no comment
No
GE has no comment for MOD-026
Yes
GE has no comment
Yes
GE has no comment
Yes
GE has no comment
Yes
The requirement is achievable in concept, however, there is a serious omission in the definition of the requirement. It is not clear how the magnitude of the three phase voltage is defined, for example: average of the individual phase magnitudes, magnitude of the least phase, positive sequence. Also, it should be clearly defined whether the requirement applies to the rms, 60 Hz component, or peak magnitude of the voltage.
Yes
GE has no comment
Yes
Clause 6.1.1 allows an exception from meeting the ride through requirements for voltage support equipment that is not in service. Often such equipment is installed solely for the purpose of acheiving ride through. It is not clear that there are any NERC standards requiring that this equipment be maintained to have a minimum level of availability. As worded, this clause could create a means by which a GO could indefinitely avoid requirements, and subsequent penalties for non-compliance.
Group
Public Service Enterprise Group
John Seelke
No
No
If the SDT were to prepare a table showing how the requirements in the prior version were incorporated into the present version and included that in its background information on the standard, this question would be answered.
Yes
The team needs to develop a consistent rationale on synchronous condensers in all of the standards being addressed in Project 2007-09. The team should consider asking the NERC Planning Committee to develop a white paper on the need (or lack of need) for synchronous condenser data.
Yes

1. The capacity factor calculation referenced in 4.2 should refer to a future attachment that the team would develop that explains (a) which reliability standard one would use to for a unit's capacity rating (such as MOD-010) for the calculation and (b) a sample calculation. 2. In 4.2.4, the sentence "Any technically justified unit requested by the Planning Coordinator" should specify (a) the entities that may develop the technical justification, (b) the entity who will evaluate that technical justification and (c) the criteria for judging whether an excluded unit should be included. 3. In R1, first bullet: a. Would the instructions issued by the Transmission Planner on "on how to obtain the list of acceptable excitation control system and plant volt/var control function model for use in dynamic simulation" cover "acceptable" verification via staged tests and "acceptable" verification by a measured system disturbance per R2.1.1. b. Are Transmission Planners the appropriate entity to determine "acceptability" of models or verification since there are about 120 Transmission Planners registered in the Eastern Interconnection? See the comment below regarding R2.1.1 4. R2.1.1 addresses verification via either staged tests or a measured system disturbance. However, the standard leaves the judgment of the acceptability of verification performed by a GO to the Transmission Planner. We suggest that the team include an attachment to the standard that provides guidance for how to perform acceptable verification, covering both staged testing and a measured system disturbance. 5. R5 is unclear. For example, does the 90-day submission period in 5.1 address submissions under 5.2 and 5.3, or does it require that the GO merely acknowledge receipt of the request within 90 days? Since 5.2 addresses plans to verify a model, why would "corrected" data in 5.3 be due within 90 days? 6. Both R3 and R5 require GO action in response to a notification by a Transmission Planner (R3) or a Planning Coordinator (R5). Can a Transmission Planner or Planning Coordinator require a response from a GO for generators that are not yet verified by the GO per the timetable in section 5? If not, it appears that R3 and R5 should be rewritten to recognize this limitation. 7. The July 29 webinar made clear that generator exciter model verification applies to synchronous generators and the plant volt/var control function applies to non-synchronous generators. It would be helpful if this clarification was made in the standard itself, perhaps in the purpose statement.
Yes
Yes
A one-sentence statement should be added stating that the protective relays affected by this standard are only the generator protective relays, not any other relays for the unit and/or facility.
Yes
Yes
No
Typical OEM recommended protective relay settings for generator UV are significantly more stringent than that which is outlined in Attachment 2 of the draft standard. Intuitively, it would seem that a generator and its auxiliary connect loads having the requirements to ride out 0.7 pu voltage for a period of 2 seconds is unrealistic.
Yes
a. Per the July 29 webinar discussion, R2.1.1 needs to be rewritten for clarity. b. The "exception" process in R3 and R4 is too vague as to "who" decides whether this standard applies to a generator. If a GO describes the limitations per R3 and one of the four entities listed in R4 inquires about a specific limitation, and the GO subsequently replies to that entity, is the exception confirmed? Under what circumstances a description of limitations by a GO in R3 would be challenged? Unless the exemption to this standard is made clear, the result will be confusion when the standard is approved.
Individual
Barry J Skoras
PPL Electric Utilities
No

The expression, “Units or plants” in para. 4.2 should be changed to “units” to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at ~0.1% CF does not need to test the diesel. Also, eliminate the word “to” in the expression in para. 4.2.1, “For each plant with a gross aggregate nameplate rating greater than to 100 MVA”
Yes
Yes
Yes
1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements. 2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word “software;” and para. R2.1.1 should state that “Verification consists of developing one or more models that collectively include the following information:” The present R2.1.1 text, “acceptable to the Transmission Planner,” is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO’s first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified status only after being accepted by the Transmission Planner, the term “verified model(s)” in the R2 Violation Severity Levels should be replaced with, “initial submittal of proposed-verified model(s)”. 3. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in para. R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026. 4. The definition of a “technically justified request” in para. R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.
Yes
1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary. 2. The need for excursions as severe as those of Att.2 should be confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/-1.74%) would be considered abnormal for our system (PJM).
No
Recommend the wording be changed for R1/R2 to “ Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following…”
No
1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5. 2. The question above cites “frequency and voltage excursions [emphasis added],” the question 4 below deals with “frequency or voltage excursions,” para. R5.1 states “Frequency Excursion…and a Voltage Excursion” and para. R6 references “Frequency Excursion or Voltage Excursion.” The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. 3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be

one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. 4. In the event that R5 remains as-is, a standard-specific definition of the word “plant” is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit’s behavior. 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024.
Yes
1. Excursion-estimate requirements for new units are presented in R6, not R5. Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult.
No
Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Yes
1. The term “continuous capacity rating” in the second bull-dot item of R3 should be replaced with “Normal Rating or Emergency Rating,” to eliminate ambiguity via use of NERC Glossary-defined terms. 2. The term “non-protection system” in R3 should be replaced with “non-Protection System,” to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable). 3. Paras. R5.1 and R5.2 suffer in terms of clarity from consisting of a single sentence that is over 80 words long, with not a single comma or semicolon to guide the reader. NERC standards should make use of normal technical-writing style and punctuation
Group
PPL Supply
Annette Bannon
No
The expression, “Units or plants” in para. 4.2 should be changed to “units” to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at ~0.1% CF does not need to test the diesel. Also, eliminate the word “to” in the expression in para. 4.2.1, “For each plant with a gross aggregate nameplate rating greater than to 100 MVA”.
Yes
Yes
Yes
1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements. 2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word “software;” and para. R2.1.1 should state that “Verification consists of developing one or more models that collectively include the following information:” The present R2.1.1 text, “acceptable to the Transmission Planner,” is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO’s first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified

status only after being accepted by the Transmission Planner, the term “verified model(s)” in the R2 Violation Severity Levels should be replaced with, “initial submittal of proposed-verified model(s)”. 3. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in para. R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026. 4. The definition of a “technically justified request” in para. R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.
Yes
1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary. 2. The need for excursions as severe as those of Att.2 should be confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/- 1.74%) would be considered abnormal for our system (PJM).
No
1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5. 2. The question above cites “frequency and voltage excursions [emphasis added],” the question 4 below deals with “frequency or voltage excursions,” para. R5.1 states “Frequency Excursion…and a Voltage Excursion” and para. R6 references “Frequency Excursion or Voltage Excursion.” The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. 3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. 4. In the event that R5 remains as-is, a standard-specific definition of the word “plant” is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit’s behavior. 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024.
Yes
1. Excursion-estimate requirements for new units are presented in R6, not R5. Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult.
No
Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Yes
1. The term “continuous capacity rating” in the second bull-dot item of R3 should be replaced with “Normal Rating or Emergency Rating,” to eliminate ambiguity via use of NERC Glossary-defined terms. 2. The term “non-protection system” in R3 should be replaced with “non-Protection System.”

to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable). 3. Paras. R5.1 and R5.2 suffer in terms of clarity. Suggest rewording these paragraphs to make them easier to understand. 4. An exception should be added for nuclear facilities that may not be able to ride through the frequency and voltage excursion outline in PRC-024 with out impact to nuclear safety systems.
Individual
Andrew Z. Pusztai
American Transmission Company
No
Yes
Yes
ATC believes that synchronous condensers may have significant impact in the areas where they are installed. Therefore, ATC agrees that they should be added to the NERC Compliance Registration Criteria and that a separate SAR should be established to develop a separate reliability standard for synchronous condensers and other dynamic reactive devices.
Yes
Please give consideration to the following suggestions: 1. In Applicability, 4.2, Include the explanation that “average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value” since some have asked how this value is defined and calculated. 2. In Applicability, 4.2.4 - add “Transmission Planner” to this item because Transmission Planners may also have insight and the means to provide technical justification for the inclusion of specific units in their system. 3. In Requirements, R1, bullet 1 - remove this bullet 1, or combine it with bullet 2, because it appears to be redundant with bullet 2, rather than distinctly different. 4. In Requirements, R2.1.4 - replace “model structure and data” with “block diagram and model parameters” for more clarity. 5. In Requirements, R2.1.6 - replace “model structure and data” with “manufacturer, model number, block diagram, and model parameters” for more clarity and specificity. 6. In Requirements, R2.1.6 - add ”and indicate whether the power system stabilizer is planned to be in-service and out-of-service in the planning horizon.” 7. In Requirements, R4 – revise the text from “within 180 days of making changes” to “within 180 prior to making changes” for more clarity.
Yes
Yes
Yes
Yes
Yes
Yes
Please give consideration to the following suggestions: 1. In Requirements, R1, R2, & R3 – include a footnote for the references to “non-protection system equipment” that defines or gives a few examples of this equipment to add clarity. 2. In Requirements, R3 – add the requirement that the GO provides the expected duration of the limitation, if it is known. 3. In Requirements, R5.2 – include a footnote or example of “25% estimated probability increments” to add clarity. 4. In References – include references that provide more technical justification and background for the voltage and frequency limits given in Attachment 1 and Attachment 2. 5. In Attachment 1 - add a “Return to between 59.5 Hz and 60.5 Hz frequency” text box to be consistent with the labeling in Attachment 2. 6. In Attachment 1 – add the title “Curve Data Points” to the Frequency/Time table to be consistent with Attachment 2. 7. In Attachment 2 – modify HVRT and LVRT tables (perhaps combine them into

one more compact table) to be consistent with the table in Attachment 1 and fit on the same page. 8. In Attachment 2, 5a - expand to “Power factor is 0.95 lagging (i.e. supplying reactive power to the system as measured at the generator terminal)” to be more definitive.
Group
Florida Municipal Power Agency
Frank Gaffney
Yes
FMPA appreciates the efforts of the SDT to “right-size” the applicability to plants that truly impact the stability response of the system. However, the words used in the draft standard allow a loop-hole to the SDT’s intent. Footnote 4 to the Applicability section states: “(a) technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response”. If a region wishes to include 1 MW generators in the process, all they have to do is show that the unit’s actual response does not match the simulated response without a technical justification to show that the 1MW generator has any impact on the actual stability response of the system. The SDT should change the “or” in footnote 4 to “and” meaning that the technical justification needs to include both an impact to a stability limit AND a difference between actual and simulated response. In addition, for R5 and footnote 4, who judges what is and what is not a “technical justification”? For instance, NPCC in their regional UFLS standard proposed to cause 1 MW generators to register and be included in the standards. Does the region have the final say on technical justification? The staged test in R2.1.2 and Attachment 1 that is required if an actual event does not occur is onerous. FMPA believes this “staged test” is impractical and should be eliminated. Within a ten year period, an actual event is likely to occur resulting in a recorded response. If an actual event does not occur, then, the risk of inaccuracy is small and a “staged test” with associated higher risk should not be required to only marginally improve accuracy.
Yes
No
The term “protective relaying” is confusing in two ways: 1) the footnote is ambiguous as to how it applies; and 2) it calls into question whether this is a “generation Protection System” applicable to PRC-004 and PRC-005 (especially when considering the inconsistent use of “non-protection system equipment” in R3). FMPA suggests the term “safeguard” instead of “protection”, e.g., a “frequency safeguard system” to avoid this ambiguity and with a footnote to make more clear that systems like GE Mark VI’s are or are not included. Similarly in R2, it is unclear what “voltage protective relaying” is. FMPA suggests using the word “safeguard” instead of “protection”. Also, it is unclear whether station service voltage safeguards are included, such as motor contactors. In addition, “external to the plant” as used in several requirements (e.g., R1, R2 and R6) is ambiguous. We assume that this would also mean beyond any radial connection (e.g., generator lead) to the plant and would suggest changing the term to something like: "caused by an event beyond the point at which the plant is radially connected to the transmission system".
No
R4 is missing the VRF and Time Horizon. FMPA recommends “Lower” and “Long-term Planning”.
No
First, FMPA believes the SDT is referring to R6 not R5. Technically, the requirement is inconsistent with the question. The requirement is to design, build and maintain to prevent tripping, it does not say “thou shall not trip”. If a generator is designed, built and maintained to specifications that should not trip, but, a generator trips anyway in a real-life event, is that a violation?
Yes
The bullets in R3 are onerous. The bullets would essentially eliminate the ability to replace like-with-like which would have an impact on spare equipment strategy and stores since existing spares in the

warehouse could not be used. If spares were not available that could meet the new criteria, the GO would be forced to either keep a unit off-line or be non-compliant. FMPA suggests eliminating the bullet, or at most, institute something like a Cyber Security Technical Feasibility Exception (TFE) process. In addition, in the bullets at the end of R3, is the 10% incremental or cumulative over time? E.g., if a GO does a capacity augmentation of 5% one year and then another 5% increase 3 years later, does that trigger the 10%? R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" between minimum and maximum output of the generator implied?
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
Mostly, HQT's frequency and voltage curves are more stringent for generators, as the area for no trip zone is wider. However, the following points on those curves of attachment 1 and attachment 2 are too stringent and we ask to consider these modifications: • On the frequency curve, for wind or thermal generation only, the no trip zone between 0 and 5 seconds should be limited to an over frequency of 61,7 hz. • On the voltage curve, the no trip zone should be restricted as follow: ♣ Between 1 and 2 seconds, to 0,75 pu, ♣ Between 2 and 3 seconds, to 0,85 pu.
Yes
Yes
The graph of voltage from the interconnexion of Quebec was reflected from the FERC order 661-A which is different from the graph from this standard. Please justify the source of the present standard.
Individual
Scott Berry
Indiana Municipal Power Agency
No comment
no comment
no comment
Yes
IMPA appreciates the efforts of the SDT on getting the applicability section correct for the plants or units that truly impact the stability response of the BES. However, the standard does contain a loop-hole to the SDT's intent. On page 3 of 16, footnote 4 to the applicabilty section (4.2.4)states: "a technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response". The first or word in that sentence should be replace with the word "and". A technical justification for verifying each of those units and plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit should both be required. By requiring both of these items, it might prevent units the size of 1MW from having to perform this standard. In addition, who qualifies what is a technically justified unit or what is a technical justification? Past history as shown that technicaly justifications have been used "losely" by different regions and entities. The Generator Owner should have some means of appealing this request by the Planning Coordinator.
no comment
No

The term "protective relaying" is confusing in a two ways: 1) The footnote needs to clarify how it applies; and 2)the term calls into question whether this is a "generation Protection System" applicable to PRC-004 and PRC-005. It needs to be made more clear that systems like the GE Mark IV and VI control systems are or are not included. R2 is also not clear when using "voltage protective relaying". It is not clear if voltage safeguards on motor contactors are included. The standard also needs to make more clear what "external to the plant" exactly means.
No
This is actually requirement R5. IMPA does not see any value in assigning a standard requirement to a Generator Owner that is just an estimation of performance when it might be a far off estimation of performance compared against actual performance of an existing unit or generating plant. This standard should concentrate on the setting of relays and not have Generator Owners estimate how their unit or generating plant will perform during a Frequency/Voltage Excursion. This standard should also not force Generator Owners to perform studies or model their unit or generating plant since they are not guaranteed or reliable either.
No
This is actually requirement R6. IMPA does not believe this technology is currently achievable for new units or generating plant/facilities on all generation producing fronts. The technology should be in place and proven on all generation fronts before such writing of standard requirements.
no comment
no comment
Individual
Armin Klusman
CenterPoint Energy
No
(a) CenterPoint Energy agrees with the time duration value of the 0.9 pu voltage level up to 600 seconds and believes this will coordinate with existing undervoltage load shedding systems (UVLS). However, CenterPoint Energy believes there are numerous relays presently set at 2.0 seconds and 3.0 seconds to shed load in a voltage excursion and, therefore, there is not a sufficient margin for coordination at the two second and three second low voltage points in Attachment 2. CenterPoint Energy recommends these two points in Attachment 2 be revised to 2.5 and 3.5 seconds. That is, the data points (Time / Voltage) in the LVRT DURATION table would be as follows: 0.15 / 0.000, 0.30 / 0.450, 2.50 / 0.650, 3.50 / 0.750, and 600 / 0.900. (b) In addition, CenterPoint Energy believes there is insufficient margin at 1.0 seconds for high voltage ride through due to voltage over-shoot following a zone 1 fault. To provide an adequate margin, CenterPoint Energy recommends the 1.0 second high voltage point in Attachment 2 be revised to 1.5 seconds. That is, the data points (Time / Voltage) in the HVRT DURATION table would be as follows: 0.20 / 1.200, 0.50 / 1.175, 1.50 / 1.150, and 600 / 1.100.
Yes
(a) CenterPoint Energy does not agree with limiting the applicability of Requirement 2 to just “voltage protective relaying”. In effect, this would allow possible tripping of generation during off nominal voltage excursions from several other types of relays, such as generator backup over-current and impedance. CenterPoint Energy recommends that this standard be applicable to any generator Protection System relays that operate on voltage and / or current. (b) In Requirement 2.1.1, the fault clearing time should be established at a fixed 9 cycles, instead of site-specific, actual clearing times. R2.1.1 should be written as: “For three-phase transmission zone 1 faults, set generator Protection System relays based on a fault clearing time of 9 cycles”. (c) Requirement 2.1.2 provides for location-

specific criteria that are unnecessary and could have unintended consequences, as such criteria can change over time with additions and modifications of the bulk electric system. CenterPoint Energy believes NERC reliability standards should not include fill-in-the-blank, location-specific criteria and recommends R2.1.2 be deleted.
Group
NERC Staff
Mallory Huggins
No
We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
Yes
No
It is most efficient to address synchronous condensers in the same project as generators given that synchronous condensers have many of the same characteristics as generators. Static var compensators (SVCs) and static compensators (STATCOMs) are sufficiently different from generators and synchronous condensers to be appropriately covered in a separate SAR. Despite the low penetration of synchronous condensers in North America, these devices are most likely installed to extend a dynamic voltage security limit as noted by the drafting team. Due to the importance of these devices, validated models should be required for these devices similar to generators. Reliance on other motivations for equipment owners to validate models is inconsistent with requirements for generators and does not provide appropriate assurance that the equipment owners will validate models necessary for system reliability.
Yes
Validation of the voltage and reactive power response of generating units for significant system disturbances indicates that the dynamics database quality is not as robust as noted in the Background Information posted with this standard. As a result NERC staff offers the following three specific comments for improving the quality of the model database: 1) It is not possible to accurately model system voltage and reactive power response with valid models for only 80 percent of the installed system capacity. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per the SDT estimates this will assure accurate modeling for approximately 95 percent of installed capacity. 2) We disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions when reactive support may be most critical thereby making valid models critical to system reliability during those conditions. While they should not be exempted from the standard, we do believe it may be appropriate to assign these units lower priority in the implementation plan. 3) The initial completion of validation for all applicable units and periodicity for model verification should be 5 years, not 10 years. The 10 year time is excessive. Any Functional Model entity that requires the models, including Planning Coordinators, Transmission Operators, and Reliability Coordinators, should be permitted under Requirement R3 to provide notification to the Generator Owner that the model is not usable or that the predicted response did not match the recorded response to a transmission system event. Also, Requirement R3 should permit entities to notify the Generator Owner that the model is not usable for any reason. We recommend removing the list referencing Requirement R6, parts 6.1 through 6.3, because it is not and cannot be an all-inclusive list of problems that could make the model not usable (e.g., the model could cause the simulation software to “freeze”). In the first row of the Periodicity Table, transmission of the verified model and documentation to the Transmission Planner should occur within 180 days from the date the recorded response is collected similar to all other rows in the table. There is no apparent basis for the additional time provided in the first row of the table. The violation risk factors associated with Requirements R1 through R6 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R6 should include the operations planning horizon. In

Requirement R6, part 6.2, the reference to negligible transients is not measurable. We recommend modifying this to ". . . results in a response that varies less than the numerical stability of the program used for the simulation." In Requirement R6, part 6.3, the introductory phrase "For an otherwise stable simulation" is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with "A disturbance simulation results in . . ." The SDT should consider use of the word validation instead of verification and assure that the terms used in this standard are consistent with other standards.
No
NERC staff believes it is unnecessary to define these terms to achieve the reliability objective of this standard. We further note that the proposed definitions of these terms are in conflict with usage of the phrases frequency excursion and voltage excursion in other standards and a defined glossary term. A review of existing NERC standards and the NERC glossary identifies the following inconsistencies: (1) Standard BAL-003-0.1b "requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting." Events identified for use in analyzing and setting requirements for frequency response are associated with frequency deviations of less than ±0.5 Hz, and not necessarily deviating from 60 Hz. (2) Standard EOP-004-1 requires reporting for "any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in sustained voltage excursions equal to or greater than ±10%." (3) Standard PRC-006-1, refers to "system frequency excursions below the initializing set points of the UFLS program." The initializing setpoints of UFLS programs vary by region. (4) The defined term, Disturbance Monitoring Equipment, includes "Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions." We also observe inconsistency within the draft PRC-024-1 which refers to "a Frequency Excursion defined by the curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2," which is in conflict with the proposed definitions. Given the range of contexts in which the phrases frequency excursion and voltage excursion are used we believe it is most appropriate that each standard identify the excursions of interest in the context of that standard, rather than establishing defined terms with specific numerical values.
Yes
Yes
Yes
Yes
Yes
The applicability section should be expanded to address both applicable entities and applicable facilities similar to MOD-025-2 and should apply to individual generating units >20 MVA (gross nameplate rating) and generating plants/Facilities >75 MVA (gross aggregate nameplate rating), regardless of interconnection voltage. The percentage of units that must be compliant in Effective Date sections 5.1.1, 5.2.1, and 5.3.1 should be based on an MVA basis similar to other standards in Project 2007-09, such that the phrase "% of its applicable units" is replaced with "% of its applicable units on an MVA basis." The SDT should consider the implications of Requirement R1, part 1.5, which appears to preclude unit tripping when frequency rate-of-change is less than 2.5 Hz/s, even if the frequency is above 62.2 Hz or below 57.8 Hz. The voltage curves in Attachment 2 should be applicable for any operating condition that falls within the voltage-time curves regardless of the initiating event that causes the voltage excursion. As such, Requirement R2, part 2.1.1 should be removed from the standard. Also, we understand from the webinar that the voltage curves in Attachment 2 represent positive sequence voltage. If voltage relays that sense phase-to-ground or phase-to-phase voltage are set according to this curve, generator tripping could occur for normally cleared unbalanced faults (e.g., the unfaulted phase voltage during a single-line-to-ground may exceed 1.2 per unit on an effectively grounded system). The drafting team must develop curves that can be used directly for setting protective relays to assure that generators remain connected for both balanced and unbalanced faults. System conditions may change more quickly than a Transmission

Planner can identify and convey applicable voltage relay setting requirements to a Generator Owner. We are not aware of any reason a Transmission Planner would require less stringent criteria than Attachment 2. For these reasons, the following items should be deleted: (1) Requirement R2, part 2.1.2; (2) The phrase referring to "the voltage profile at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault . . ." in Requirement R5, parts 5.1 and 5.2; (3) Requirement R6, part 6.3; and (4) Note 2 to the Voltage Ride-Through Curve Clarifications. Equipment limitations will not change based on modifications to changes in generating unit capacity. The second sentence in Requirement R3 should be changed from "the equipment limitation expires . . ." to "The waiver for compliance with Requirements R1 and R2 associated with the equipment limitations expires . . ." The conditions in Requirement R6, parts 6.1 and 6.2 could be interpreted to indicate that this requirement only applies to generating plants/Facilities greater than 75 MVA. The standard should be revised to be clear that it also applies to generating units greater than 20 MVA.
Individual
Dan Hansen
GenOn Energy
No
The comment is for R5 for the June 15, 2011 draft. The wording is too open-ended and subjective in scope. Similar to R1 & R2, the requirement should be clearly defined and limited to devices that directly respond to generator voltage or frequency. R3 already requires the information of other control or protective devices. Typically, the Generator Owner does not monitor the interconnection voltage for protection purpose; rather generator terminal voltage is used for generator protection. The modeling is performed by others, but the burden of analysis is being placed upon the Generator Owner to determine performance probability for information not in their possession. 30 days is a short period of time for this analysis when hit cold with a request like this, especially during outage season.
No
Applied to R6 of the June 15, 2011 draft. It does not appear that the SDT has carefully considered the possible impact of Attachment 2 on plant electrical auxiliary motors and contactors. The SDT should ask an power plant engineering company the impact on the electrical auxiliaries of an 800MW coal unit with a scrubber.
No
10 minutes is a long time for some unavoidable configuration of electrical auxiliaries.
Yes
A strong disapproval of the R3 equipment limitation expiration with a generating unit rating increase of 10%. The expiration is unnecessary and is based upon an arbitrary criterion that may be totally unrelated to basis for the limitation. A backwards approach has been taken with the application of Attachment 2, which represents very poor performance of the transmission system for voltage recovery after a fault. This standard will have the affect of permanently defining this as acceptable transmission performance, which should not be the case. This is inequitable since it imposes the lowest common denominator of one segment of the industry and unilaterally transfers the responsibility for that performance upon another seqment (every generating unit on the continent). The Generator Verification team has developed extensive requirement for Generator Owners to provide accurate model data for system studies, but Generator Owners get no benefits in return for their effort and expense. Rather than imposing Attachment 2 on Generator Owners, the more correct way is to require Planning Coordinators, Transmission Operators or Transmission Planners to provide planning study results and voltage recovery profile at the generator terminals (this is where the protection and controls are applied). This will enable Generator Owners correctly apply protection settings as appropriate. Another option is to drive performance improvements on the Transmission

system. Attachment 2 should be set a much higher standard of performance of the transmission system (median or higher), and require the Planning Coordinators, Transmission Operators or Transmission Planners to identify the locations where the higher standard is not attainable and provide the voltage recovery profile.
Group
Bonneville Power Administration
Denise Koehn
No
Yes
Yes
Yes
MOD-026: By making Transmission Planners responsible for generator verification instead of regional entities, it may be more difficult to produce integrated regional models. The standard should also apply to Regional Coordinators to ensure consistent generator verification requirements within regions.
No
R2.1.1 – Please clarify/verify: • That the allowable voltage relay trip time is greater than the normal fault clearing time up to a normal clearing time of 9 cycles; • That tripping is allowed above 9 cycles regardless if it is normal clearing or backup clearing; and, • That for generators in close proximity the normal clearing time is coordinated to ensure it is no greater than what a specific generator was designed to withstand.
No
R3-R4 - Generator Owners may be unwilling to share proprietary information in response to requests from Reliability Coordinators, Planning Coordinators, Transmission Operators, or Transmission Planners, because of manufacturer restrictions or for other reasons. Should the standard anticipate this issue?
R5 - WECC Reliability Subcommittee discussions indicated that protection generation relay performance at the Point of Interconnection was different than if the measurement point is at the low side or high side of the step-up transformer. The NERC Standard should specify the measurement point at the high side of either the generator step up transformer, or at the high side of the collector transformer where multiple small generators are aggregated at a collector substation. Attachment 2 – BPA suggests modifying the diagram to reflect changes to Requirement R2.1.1 above, e.g. to show that allowable voltage relay trip time is greater than the normal fault clearing time if the normal clearing time is less than 9 cycles.
Yes
The proposed standard uses both "zone 1" and "Zone 1", which we assume mean the same thing. What is the source of the Zone 1 determination?

Consideration of Comments on Generator Verification – MOD-026-1 — Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the Second Posting of MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions. These standards and associated documents were posted for a 45-day public comment period from June 15, 2011 through August 1, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. Also included in this report are comments received from the initial ballots and non-binding polls conducted during the last ten days of the 45-day comment period. There were 66 sets of comments, including comments from approximately 185 different people from approximately 120 companies representing all 10 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT asked stakeholders if they believed any additional generation configurations should be considered for applicability under this standard. None of the comments identified other generation configurations/types that should be covered in the applicability. Several commenters recommend making the standard applicability match the compliance registry while other commenters recommend removing the requirement to verify small generator units from the standard applicability. The SDT believes:

- The standard is drafted to provide the proper cost/benefit balance for performing generator verification.
- It is not necessary to have models verified for all units listed in the compliance registry.
- Proposed applicability thresholds will substantially improve the accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

The SDT recognizes that the excitation system model and modeling data is already captured by the MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database. Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation. Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds which correspond to at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification. Concern was raised that the language of R5 could require verification of units with ratings less than the thresholds specified in the registry criteria. The SDT asserts that any unit not included in the standard Applicability and deemed to require verification as justified by the Planning Coordinator must, by definition, satisfy the Registry Criteria threshold established. The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit. This is not the case.

A few commenters expressed concern that the standard does not require the Generator Owner to notify the Transmission Owner of new equipment and provide the Transmission Planner preliminary models based on OEM design data. The SDT reminds that the scope of the draft standard is model verification, which can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process.

Also in response to industry comments, the SDT has inserted a footnote in the standard to make clear that standby generator models are not required to be verified.

The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that Synchronous Condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.

The GVSDT received many comments concerning various aspects of the standard. As a result of these comments, the SDT has made a number of modifications to the standard including:

1) Correcting several VSL grammatical errors and ensuring consistency between the VSL "increment for tardiness" time period specified and the Requirement language.

2) An additional condition, row 12, was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service.

3) The format and column information of Attachment 1 has been revised for clarity.

4) The typographical errors in R2.1.1 language has been corrected to clearly state expectation that “the unit or plant’s model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance.”

5) The language of R2.1.4 has been revised to align with the style of R2.1.6.

6) Several commenters expressed concern with the new Requirement R5 added to the standard giving the Planning Coordinator authority to require a model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. In addition, R5 language has been revised for clarity.

7) To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).

8) There was some confusion regarding the treatment of small units at plants. The SDT modified the language in the Applicability / Facilities section for clarity and for consistency to the extent possible with the other draft standards in the Generation Verification effort.

As a reminder, the SDT, in its response to industry comments, points out this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.

Index to Questions, Comments, and Responses

1. The Applicability section of MOD-026 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability? 15

2. The current version of the MOD-026 standard has been re-formatted so that it would be more concise and contain only reliability related requirements. Do you agree there are no omissions from the prior draft due to the re-formatting of the standard? 29

3. The SDT discussed if MOD-026-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR. 38

   Do you agree with the proposal to not include the verification of synchronous condensers in MOD-026-1? 38

4. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain. 50

END OF REPORT 112

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	David Thorne	Pepco Holdings Incand Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3
2.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Jesus Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Marcela Caballero	IID	WECC	5
5.	Cathy Bretz	IID	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Jason Marshall	ACES Power Members						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Jones	AEPCO/SWTC	WECC	1, 3, 5
2.	Mohan Sachdeva	Buckeye Power	RFC	3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Joe Spencer - SERC staff	SERC Generation Sub-committee (GS)										X
7.	Group	Tim Brown	Idaho Power - Power Production					X					
8.	Group	Jonathan Hayes	SPP Reliability Standards Develpment Team		X								

(continued, additional members of previous group)

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
2.	Pat G. Harrington	BC Hydro and Power Authority	WECC	3
3.	Clement Ma	BC Hydro and Power Authority	WECC	5
4.	Daniel O'Hearn	BC Hydro and Power Authority	WECC	6

Group 6 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Camilletti	Santee Cooper	SERC	
2.	Sam Dwyer	Ameren Missouri	SERC	
3.	David Thompson	TVA	SERC	
4.	Robin Wells	LG&E/KU	SERC	
5.	Chris Georgeson - chair	Progress Energy	SERC	
6.	Chris Schaeffer	Duke Energy	SERC	
7.	Dale Goodwine	Duke Energy	SERC	
8.	Brad Haralson	AECI	SERC	
9.	Kumar Mani	Progress Energy	SERC	
10.	Joe Spencer	SERC Reliability Corp	SERC	

Group 7 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Guy Colpron	Idaho Power	WECC	5
2.	Mark Pfeifer	Idaho Power	WECC	5

Group 8 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clem Cassmeyer	Western Farmers	SPP	1, 3, 5
2.	Craig Henry	Oklahoma Gas and electric	SPP	1, 3, 5
3.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4.	Louis Guidry	CLECO	SPP	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Lynn Schroeder	Westar energy	SPP	1, 3, 5, 6
6.	Mahmood Safi	OPPD	SPP	1, 3, 5
7.	Robert Cox	Lea County Electric	SPP	
8.	Thomas Hestermann	Sunflower Electric	SPP	1
9.	Valerie Pinamonti	AEP	SPP	1, 3, 5
10.	Robert Rhodes	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5
14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Mike Garton	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

		Region	Segment Selection
2. Louis Slade		RFC	5, 6
3. Mike Garton		NPCC	5
4. Michael Gildea		MRO	5
5. Matthew Woodzell		SERC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Joe Spencer - SERC staff	Dynamics Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Camilletti	Santee Cooper	SERC	
2.	Sam Dwyer	Ameren Missouri	SERC	
3.	David Thompson	TVA	SERC	
4.	Robin Wells	LG&E/KU	SERC	
5.	Chris Georgeson - chair	Progress Energy	SERC	
6.	Chris Schaeffer	Duke Energy	SERC	
7.	Dale Goodwine	Duke Energy	SERC	
8.	Brad Haralson	AECI	SERC	
9.	Kumar Mani	Progress Energy	SERC	
10.	Joe Spencer	SERC Reliability Corp	SERC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				

No additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bill Duge	FE	RFC	5
2. Ken Dresner	FE	RFC	5
3. Mike Williams	FE	RFC	5
4. Brian Orians	FE	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Rene Free	Santee Cooper	SERC	1
3.	Bridget Coffman	Santee Cooper	SERC	1
4.	Paul Camilletti	Santee Cooper	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Mueller	PSE&G	RFC	3
2.	Ken Brown	PSE&G	RFC	1
3.	Mikhail Falkovitch	PSEG Fosssil	RFC	5
4.	Peter Doln	PSEG ER&T		6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Annette Bannon	PPL Supply					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
2.		PPL Brunner Island, LLC	RFC	5
3.		PPL Holtwood, LLC	RFC	5
4.		PPL Martins Creek, LLC	RFC	5
5.		PPL Montour, LLC	RFC	5
6.	Dave Gladey	PPL Susquehanna, LLC	RFC	5
7.	Leland McMillan	PPL Montana, LLC	WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	Utilities Commission, City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Mallory Huggins	NERC Staff Review Team										

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3
2.	Chuck Matthews	BPA, Transmission Planning	WECC	1
3.	Erika Doot	BPA, Generation Support	WECC	3, 5, 6
4.	Mike Alder	BPA, Federal Hydro Projects	WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Individual	David Thompson	TVA - GO					X					
21.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
22.	Individual	Bo Jones	Westar Energy	X		X		X	X				
23.	Individual	David Youngblood	Luminant Power					X					
24.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
25.	Individual	Scott Sweat	Westinghouse					X					
26.	Individual	Antonio Grayson	Southern Company	X		X			X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	Edward Cambridge	APS	X		X		X					
29.	Individual	Michael Goggin	American Wind Energy Association								X		
30.	Individual	Samuel Reed	Tri-State Generation and Transmission, Inc.	X				X					
31.	Individual	Bob Casey	Georgia Transmission Corporation	X									
32.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					
33.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
34.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
35.	Individual	John Bee on behalf of Exelon	Exelon	X		X		X					
36.	Individual	Eric J Anderson	New York Power Authority	X		X		X					
37.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
38.	Individual	Tom Flynn	Puget Sound Energy	X		X		X					
39.	Individual	Jeanie Doty	Austin Energy					X					
40.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
41.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
42.	Individual	James R. Keller	We Energies			X	X	X					
43.	Individual	Linda Horn	We Energies			X	X	X					
44.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
45.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
46.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
47.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
48.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
49.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
50.	Individual	Kathleen Goodman	ISO New England Inc.		X								
51.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
52.	Individual	Brad Jones	Luminant Energy						X				
53.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
54.	Individual	Kirit Shah	Ameren	X		X		X	X				
55.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
56.	Individual	Larry Grimm	Texas Reliability Entity										X
57.	Individual	Anthony Jablonski	RFC										X
58.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
59.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
60.	Individual	Gary Chmiel	GE Energy										
61.	Individual	Barry J Skoras	PPL Electric Utilities	X									
62.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
63.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
64.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
65.	Individual	Armin Klusman	CenterPoint Energy	X									
66.	Individual	Dan Hansen	GenOn Energy					X					

1. **The Applicability section of MOD-026 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability?**

Summary Consideration: None of the comments identified other generation configurations/types that should be covered in the applicability.

Several commenters recommend making the standard applicability match the compliance registry while other commenters recommend removing the requirement to verify small generator units from the standard applicability. The SDT believes:

- **The standard is drafted to provide the proper cost/benefit balance for performing generator verification.**
- **It is not necessary to have models verified for all units listed in the compliance registry.**
- **Proposed applicability thresholds will substantially improve the accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.**

The SDT recognizes that the excitation system model and modeling data is already captured by the MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database. Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation. Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds which correspond to at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification. Concern was raised that the language of R5 could require verification of units with ratings less than the thresholds specified in the registry criteria. The SDT asserts that any unit not included in the standard Applicability and deemed to require verification as justified by the Planning Coordinator must, by definition, satisfy the Registry Criteria threshold established. The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit. This is not the case.

A few commenters expressed concern that the standard does not require the Generator Owner to notify the Transmission Owner of new equipment and provide the Transmission Planner preliminary models based on OEM

design data. The SDT reminds that the scope of the draft standard is model verification, which can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process.

Finally, in response to industry comments, the SDT has inserted a footnote in the standard to make clear that standby generator models are not required to be verified.

Organization	Yes or No	Question 1 Comment
Beaches Energy Services, Florida Municipal Power Pool, Lakeland Electric, City of Green Cove Springs, City of Vero Beach	Negative	Under Applicability - Facilities. The facilities applicability should be deleted altogether. The Statement of Compliance Registry Criteria already describes the Facilities for which a Generator Owner/Operator must register. Inconsistency with the SCRC will just lead to confusion and chaos with no benefit to BES reliability. As written, the standard could allow a Planning Coordinator to sweep in generation that do not meet the registry criteria simply by showing, as footnote 4 describes "evidence that the simulated unit or plant response does not match measured unit or plant response", without a commensurate technical justification for that unit actually having an impact to the stability response of the system. If such a small generator is truly important, the SCRC already has the ability within it to include such generation under III.c.4: "Any generator, regardless of size, that is material to the reliability of the bulk power system." We see no reason to vary from the SCRC. In R5, who determines whether a request is "technically justified"? "? How are disputes around "technical justification" resolved?

Response: The SDT thanks you for your comment. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.

The SDT believes proposed applicability thresholds that will substantially improve the accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.

Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.

Organization	Yes or No	Question 1 Comment
Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard. The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.		
Lakeland Electric	Negative	The Statement of Compliance Registry Criteria already describes the Facilities for which a Generator Owner / Operator must register. Inconsistency with the SCRC will just lead to confusion and chaos with no benefit to BES reliability
Response: The SDT thanks you for your comment. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry. The SDT believes the proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification. The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database. Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation. Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each		

Organization	Yes or No	Question 1 Comment
Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard. **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		
Commonwealth of Massachusetts Department of Public Utilities, Northeast Power Coordination Council, Inc., Commonwealth of Massachusetts Dept of Public Utilities	Negative	The Standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could be also be critical in some areas. The applicable criterion should be as in the Compliance Registry. The Standard allows for generators to change equipment and then notify the Transmission Planner of the change.This is unacceptable as it represents a significant relaibility concern. . The Standard still is ambiguous and should contain further definitions and clarification. The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, these units may be excluded from model verification however other standards still require that the data be supplied. **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.**		

Organization	Yes or No	Question 1 Comment
The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.** **Regarding your comment concerning equipment changes triggering a model verification, this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available. Generator Owner development of the original model during the equipment commissioning process – including iterations with transmission entities such as the submittal of preliminary models by the Generator Owner and modifications to preliminary model data should be governed by individual interconnection agreements.** **Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes such concerns are beyond the scope of this standard.** **With respect to limiters, the SDT believes coordination of these devices is addressed by another standard.**		
Public Utility District No. 1 of Lewis County	Negative	Having an engineering staff of one at our small hydro, regulary work takes a full time effort. That means plant engineering is limited. With this standard, as with many ourside consultants will have to be hired to comply at a cost estimated over $100k. Too much for a small plant with nothing to gain from effort. Therefore, I believe the threshhold for compliance should be raised. Standard should recognize that standard models are good enough to protect the BES.
Response: The SDT thanks you for your comment. Based on SDT member experiences, standard compliance cost cited is not accurate for one unit and should be substantially less than estimated. Compliance will demonstrate adequacy and efficacy of existing plant equipment; benefiting both the plant and the BES. The applicability proposed by the SDT represents effort to balance costs and benefits. “Standard” models are not adequate which is why this standard is being developed.		
BC Hydro and Power Authority	No	The Applicability section includes Generator Owners and Transmission Planners. If an entity is a Generator Owner, they will meet the NERC Compliance Registry Criteria including MVA criteria. Including phrases in section 4.2 such as “The remainder of the plant as an aggregate”, and “For all interconnections: Any technically justified unit requested by the Planning Authority” is confusing and it seems to be expanding the criteria. For example hydroelectric units that don’t qualify an entity as GO may be captured here. Also, for the aggregate, a GO may not be able to model and verify the aggregate consistent with the

Organization	Yes or No	Question 1 Comment
		method used by TPs.

Response: The SDT thanks you for your comment. The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification.

The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.

The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.

Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.

Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.

If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.

Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.

The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit.

In response to comments received, the phrase, “Remainder of the plant as an aggregate” has been revised with language that is less confusing.

Organization	Yes or No	Question 1 Comment
Idaho Power - Power Production	No	We agree with the need to include wind generation in this standard, however the applicability section seems to be overly complicated. We do not see the relevance of the 80% of connected generation as discussed above. We believe that the NERC generator registry/ BES criteria would be clear and appropriate continent wide for this standard and with many other standards. In addition, we believe that Section 4.2.4 is too open-ended. It appears to open the door for the verification of any sized machine that does not match a response, or for other open-ended reasons. Too open-ended and subjective.
Response: The SDT thanks you for your comment. The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification. **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.** **Regarding your comment concerning Section 4.2.4, the SDT believes, that while this language does allow for additional units to be evaluated, this discretion will be exercised on a limited basis since a technical justification is required. The SDT believes it is necessary to keep this language in the standard for identifying key units that, otherwise, would not be included.**		
PPL Supply	No	The expression, “Units or plants” in para. 4.2 should be changed to “units” to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at

Organization	Yes or No	Question 1 Comment
		~0.1% CF does not need to test the diesel. Also, eliminate the word “to” in the expression in para. 4.2.1, “For each plant with a gross aggregate nameplate rating greater than to 100 MVA”.
Response: The SDT thanks you for your comment. The SDT has inserted a footnote in the standard to make clear that standby generator models are not verified. In response to comments received, the phrase, “remainder of the plant as an aggregate” has been revised with language that is less confusing. The wording in 4.2.1 has been corrected. That you for the correction.		
NERC Staff Review Team	No	We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
Response: The SDT thanks you for your comment. The SDT believe Standard language is sufficiently broad not to preclude applicability to other types of resources that may be connected to the BES in the future.		
Independent Electricity System Operator	No	No, we are not aware of any. Similar to our comments on MOD-027-1, the Applicability Section of draft MOD-026-1 standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the “generating units” suffice to generally include all types of energy resources?
Response: The SDT thanks you for your comment. The SDT strove to make standard language technology neutral and purposely avoided identifying specific generating unit technologies. The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.		
Duke Energy	No	However, an exception should be made for variable energy resources for which models have not yet been fully developed and accepted. Techniques for validation of these devices have not been developed similar to generator excitation model validation tools (EPRI PPPD).
Response: The SDT thanks you for your comment. The SDT believes that models have already been developed to an adequate level of detail and are available in the planning tools. Generic models for variable energy resources have been developed in a collaborative industry effort (led by the WECC Dynamic Modeling Working Groups) and should be validated in the absence of available OEM models. Development efforts are underway to provide suitable techniques for validation of variable energy resources.		

Organization	Yes or No	Question 1 Comment
Luminant Energy	No	I am not aware of any other generation configurations/types that should be covered in the Applicability portion.
Response: The SDT thanks you for your comment.		
Consolidated Edison Co. of NY, Inc.	No	Applicability to Smaller Units:The proposed standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some local areas. The applicable criterion should be the same as those used in the Compliance Registry. No capacity factor exemptions should be allowed without a technical justification.Also see section 4.2, footnote 2. This is a broad exemption, and as we saw recently during the continent-wide heat wave, almost all units within our control area were operating. The requirement is to test once every 10 years. This is not an excessively onerous requirement.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, these units may be excluded from model verification however other standards still require that the data be supplied. **The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification.** **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the**		

Organization	Yes or No	Question 1 Comment
increasing impact renewable generation has on the BES. **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		
PPL Electric Utilities	No	The expression, "Units or plants" in para. 4.2 should be changed to "units" to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at ~0.1% CF does not need to test the diesel. Also, eliminate the word "to" in the expression in para. 4.2.1, "For each plant with a gross aggregate nameplate rating greater than to 100 MVA"
Response: The SDT thanks you for your comment. The SDT has inserted a footnote in the standard to make clear that standby generator models are not verified. In response to comments received, the phrase, "remainder of the plant as an aggregate" has been revised with language that is less confusing. The wording in 4.2.1 has been corrected. That you for the correction.		
SPP Reliability Standards Develpment Team	No	
MRO's NERC Standards Review Forum	No	
Electric Market Policy	No	
Dynamics Review Subcommittee	No	
FirstEnergy	No	
Public Service Enterprise Group	No	
Bonneville Power Administration	No	
TVA –- GO	No	

Organization	Yes or No	Question 1 Comment
Arizona Public Service Company	No	
Westar Energy	No	
Luminant Power	No	
Progress Energy	No	
Westinghouse	No	
Southern Company	No	
PacifiCorp	No	
American Wind Energy Association	No	
Tri-State Generation and Transmission, Inc.	No	
Wisconsin Public Service Corp	No	
Manitoba Hydro	No	
Exelon	No	
Dynegy Inc.	No	
Austin Energy	No	
Wisconsin Electric	No	
We Energies	No	

Organization	Yes or No	Question 1 Comment
We Energies	No	
Xcel Energy	No	
Great River Energy	No	
US Army Corps of Engineers	No	
Ingleside Cogeneration LP	No	
Southern California Edison Company	No	
Ameren	No	
American Electric Power	No	
GE Energy	No	
American Transmission Company	No	
Northeast Power Coordinating Council	No	
ACES Power Members	No	
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
Georgia Transmission Corporation	Yes	Does Applicability 4.2.4 "Any technically justified unit requested by the Planning Coordinator" override the greater than 5% capacity factor over the last three calendar years statement in 4.2? It should in the case of units needed to prevent FIDVR problems and other peak hour considerations.

Organization	Yes or No	Question 1 Comment
Response: The SDT thanks you for your comment. Paragraph 4.2.4 does provide a method by which a low capacity factor unit could be selected for evaluation.		
ISO New England Inc.	Yes	Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? The applicability criteria in this standard should be the same as the registry requirements.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, these units may be excluded from model verification however other standards still require that the data be supplied. **The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification.** **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		

Organization	Yes or No	Question 1 Comment
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
RFC	Yes	
Tacoma Power	Yes	
Imperial Irrigation District (IID)	Yes	

2. The current version of the MOD-026 standard has been re-formatted so that it would be more concise and contain only reliability related requirements. Do you agree there are no omissions from the prior draft due to the re-formatting of the standard?

Summary Consideration: None of the comments identified omissions from the prior draft. One commenter suggested that it would be easier to identify omissions if a mapping document was created. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	Negative	We do not agree with the following requirements: i. R1: Standards should stipulate the “what’s” not the “how’s”. To avoid the perception that the requirement is prescribing the “how”, we suggest simplifying the language of Requirement R1 by replacing “Instruction on how to obtain” with “Instructions for obtaining”. Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process. ii. R2.1: The phrase “models acceptable to its Transmission Planner” begs the question on what is deemed acceptable and what if the GO disagrees with the TP’s determination. To address the two issues, we suggest adding a requirement for the TP to specify the models requirements (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to “in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). iii. We are not sure why Requirement R5 is needed. First of all, it suggests that a Planning Coordinator may request the GO to perform a model review where the request can be technically justified. We wonder if the requirement really means “Transmission Planner” rather than “Planning Coordinator” since TP as the requester and model user is specified throughout the standard. Secondly, if it is indeed TP that was meant to be the requester, then would this request already been covered by Requirement R3? If not, what are the technical justifications? They are not specified in R5, unlike its R3 counterpart. Please clarify and/or revise the requirement as appropriate. iv. R6 stipulates the criteria that may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model. A computer model may fail to initialize due to reasons other than the submitted excitation control system and plant volt/var control function model itself; a no-disturbance simulation may

Organization	Yes or No	Question 2 Comment
		not result in negligible transients due to other reasons; and finally, a disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. System damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three sub-requirements. We suggest this requirement be removed. Further, in many jurisdictions the setting and tuning of excitation control systems and associated power system stabilizers, etc. are determined by the Transmission Planners (or Planning Coordinators); the GOs would simply provide the equipment and set them according to the TP's specification. In this standard, the responsibility is for the GO to verify that the model reflects the actual response of the tested equipment, whose settings have been determined prior by the other responsible entity. v. Generator model parameters need to be verified based on tests conducted during both turbine/governor model verification as well as excitation system model verification. We are however not convinced that those tests that need to be performed during the excitation system model and data verification process, to verify certain portions of the generator model parameters will be conducted as a matter of course. We therefore reiterate our view that the verification of generation model parameters needs to be included within the scope of this standard and we urge the SDT to consider our comments again. vi. The standard does not contain any provision that a TP (or PC) can request for model verification of units that do not meet the Applicability criteria but are deemed to have an impact on reliability. This could leave room for system to exhibit unstable performance for reasons indicated in our previous comments. We urge the SDT to add this provision to fill a potential reliability gap.

Response: The SDT thanks you for your comment. Since the comment contains multiple concerns, the SDT has paraphrased the comment and is responding to each concern separately for easier understanding and review:

#1. Standard shall stipulate the "what's" and not the "how's"; suggest simplifying the language of R1 by replacing "instructions on how to obtain" with "instructions for obtaining".

Response: Requirement 1 does describe the "what". The "what" is that upon request, the Transmission Planner is to provide the Generator Owner data or instructions on how to obtain needed information. Recommended language does not change the meaning of the sentence and the SDT does not believe the revision proposed would improve clarity; so the language was not changed.

#2. Bullet vs. numbers; bullets do not require compliance

Organization	Yes or No	Question 2 Comment
Response: As stated in requirement 1, the three bullets identify instructions and data the Generator Owner can request from the Transmission Planner. The Transmission Planner is only required to provide information requested. The SDT believes standard formatting is correct since the Generator Owner determines what, if any of the information identified is requested from the Transmission Planner. **#3. Not comfortable with the phrase "models acceptable to its transmission planners". Recommend adding a requirement for the Transmission Planner to specify modeling requirements or change the wording in R 2.1 to include "in accordance with models specified by the Transmission Planner".** **Response: Since the Transmission Planner is the user of the models, the models must be acceptable to the Transmission Planner in order to be deemed useful. The first bullet under R1 does require the Transmission Planner to provide instructions on how to obtain the list of acceptable models.** **#4 Why R5 is required? In R5, should it be 'Transmission Planner" rather than "Planning Coordinator". Is this request already covered in R3? If not, what is the technical justification?** **Response: The SDT added requirement R5 because sometimes a planner discovers that a model not covered in the base Applicability, which is a subset of the NERC Registry Criteria, incorrectly represents equipment. Requirement 5 provides a method to validate these models that incorrectly represents equipment and not in the base Applicability but meet the NERC Registry Criteria. This requirement is assigned to the Planning Coordinator to address Generator Owner concern that the Transmission Planner might request a model review without proper justification. The requirement is written to require a higher level of justification for requesting a model review than simply contacting the Generator Owner.** **Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.** **#5. In R6, having an accurate excitation model does not guarantee meeting requirements R 6.1, 6.2, 6.3 due to the reasons indicated. Suggest that requirement be removed.** **Response: R6.1, R6.2, and R6.3 represent established industry practice for assuring model usability. The positive damping requirement makes the Generator Owner provide a response if a new model introduces negative damping. This requirement recognizes that the equipment must be positively damped during actual operation. Negative damping occurring during simulation indicates incorrect modeling. Initialization errors and oscillation transients without disturbance conditions also indicate incorrect modeling.**		

Organization	Yes or No	Question 2 Comment
#6. How to handle settings provided to GO by TP **Response: The Generator Owner is responsible for tuning the equipment and providing the final model settings to the Transmission Planner. As a specific example, the Transmission Planner may ask the Generator Owner to implement a gain that is proven via a gain margin test to not be implementable. The Generator Owner would report the gain actually implemented on the actual equipment.** **#7. Recommend that the verification of generation model parameters be included as part of this standard.** **Response: The SDT agrees generator parameters such as the inertia constant, damping coefficient, saturation parameters, direct & quadrature axis reactance's, and time constants need to be correctly modeled. Since the phrase, "excitation control system" is an IEEE defined term with specific meaning the SDT contends this term incorporates the generation model parameters by definition. The generation model parameters must be correct to successfully verify the excitation control system model. Note that the governor turbine model verification is addressed by the MOD-027 standard. The SDT recognizes the various control systems interact and expects correct modeling data. The purpose of this standard is model verification and not the development of correct modeling parameters. If model verification is not successful, then the modeling parameters are not correct and the Generator Owner will need to identify and correct bad parameters. This standard intentionally avoids specifying how to correct model parameters with expectation the Generator Owner demonstrates that model data is correct.** **#8. Standard does not contain any provision that a TP can request for model verification of units that are deemed to have an impact on reliability? (R5 addresses this question)** **Response: Requirement 5 provides a clause that allows the Planning Coordinator to require model verification of additional units by providing suitable documented evidence. This task was assigned to the Planning Coordinator instead of the Transmission Provider to provide an extra review layer for any request to verify any additional units.** **Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.**		
Brazos Electric Power Cooperative, Inc.	Negative	This standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck. They are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are needed to accomplish the

Organization	Yes or No	Question 2 Comment
		purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6. This just represents one of the issues with memorializing the interactions between the Transmission Planner, Planning Coordinator and Generator Owner in the standards. Because the tests to verify the excitation model can be expensive, there should be a demonstrated need to perform a test. Summaries of field test results posted with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit. That does not even include opportunity costs from lost energy sales should the test cause the unit to trip. Thus, if there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the Generator Owner should be able to wait for a system disturbance appropriate enough to verify its model. Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Owner should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.

Response: The SDT thanks you for your comment. Since the comment contains multiple concerns, the SDT has paraphrased the comment and is responding to each concern separately for easier understanding and review:

#1. This standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck

Response: The SDT agrees that R2 is the main requirement for model verification. The purpose of requirements R1, R3, R4, and R5 is to provide processes to assure that the information provided per R2 is useful to the user of the information so that the reliability goal of verifying models that are used in BES security limit determination is met.

#2. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that

Organization	Yes or No	Question 2 Comment
the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6 **Response: R6 language references usability testing which can be readily completed by the Transmission Planner. R6 language is not intended to prevent the Transmission Planner from requesting the Generator Owner to verify information if there is evidence that the model is incorrect. The third bullet of R3 mandates that the Generator Owner must respond to evidence from the Transmission Planner that the modeled response does not match the recorded response and this language allows the Transmission Planner, assuming supporting evidence is available, to request a review at any time.** **#3. If there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the Generator Owner should be able to wait for a system disturbance appropriate enough to verify its model. Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Owner should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.** **Response: The SDT believes 90 days is adequate for the Generator Owner to determine if additional information is available to correct the issue or if model verification is required. The requirements do not require model verification in 90 days, only a plan to perform model verification if needed. Per Attachment 1, the Generator Owner then has 365 days to perform the test or collect an ambient event. The 90 day criteria was established to facilitate dialogue between the Transmission Planner and the Generator Owner.**		
Public Service Enterprise Group	No	If the SDT were to prepare a table showing how the requirements in the prior version were incorporated into the present version and included that in its background information on the standard, this question would be answered.
Response: The SDT thanks you for your comment. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.		
Exelon	No	Differences between draft 1 and draft 2 of MOD-026 appear to be significant. Without reading through all 134 pages of comments and how the SDT addressed those comments it is too difficult to tell how the requirements were evaluated and if omissions were intentional or not. Suggest that the SDT prepare either a mapping document or a "redline to previous version" to illustrate changes and disposition of such changes to ensure there are no omissions from the prior draft.
Response: The SDT thanks you for your comment. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.		
Independent Electricity System Operator		We are a bit surprised and disappointed that the SDT asks this question. The posted

Organization	Yes or No	Question 2 Comment
		MOD-026-1 Draft 2 is a clean version, not a redline version from last posted, making it difficult for readers to identify where the previous requirements are contained in the revised draft. We understand that a reformatting may render tracked changes to be convoluted and hence a clean version may be a better option. However, in doing so, the SDT should provide a mapping document to show where the previous requirements are mapped into the revised draft standard. Whether or not any requirements were omitted could have been and should have been identified by the SDT through the mapping process rather than by the commenters.
Response: The SDT thanks you for your comment. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.		
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
American Electric Power	Yes	AEP is not aware of any omissions from the prior draft due to the re-formatting of the standard.
Response: The SDT thanks you for your comment.		
GE Energy	Yes	GE has no comment.
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
BC Hydro and Power Authority	Yes	
SPP Reliability Standards Develpment Team	Yes	
MRO's NERC Standards Review Forum	Yes	
Dynamics Review Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
PPL Supply	Yes	
NERC Staff Review Team	Yes	
Bonneville Power Administration	Yes	
TVA - GO	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Luminant Power	Yes	
Progress Energy	Yes	
Westinghouse	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Public Service Corp	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
We Energies	Yes	
We Energies	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
Duke Energy	Yes	
US Army Corps of Engineers	Yes	
Ingleside Cogeneration LP	Yes	
Luminant Energy	Yes	
Southern California Edison Company	Yes	
Ameren	Yes	
RFC	Yes	
PPL Electric Utilities	Yes	
American Transmission Company	Yes	

3. The SDT discussed if MOD-026-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR.

Do you agree with the proposal to not include the verification of synchronous condensers in MOD-026-1?

Summary Consideration: The majority of commenters agreed with the SDT that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Negative	Manitoba Hydro is voting negative for the following reasons: 1)We disagree with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs, STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators. 2)Attachment 1 is not clear. Specifically, -the “Condition” in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be ‘verified’ and

Organization	Yes or No	Question 3 Comment
		serve as evidence for multiple units meeting the conditions listed. -the wording for the allowance of a representative unit to be verified and submitted as evidence for identical units is not clear. -the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected 'with the verified model' which is incorrect. -We suggest the following. A statement that precedes the Attachment 1 table should be added that reads 'For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ' Row 1 should then read 'Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is = 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.' 3)For Section 4.2 "Facilities", the section should refer to 'BES Generating Units and Facilities' instead of restating components of the proposed BES definition.

Response: The SDT thanks you for your comment.

1. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that:

a. **With the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.**

b. **Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**

Organization	Yes or No	Question 3 Comment
2. The SDT has revised Attachment 1 to improve clarity. **3. The SDT intentionally established the standard applicability as a subset of generators included in the NERC Registry Criteria. The term “BES Generating Units and Facilities” is not specific enough for compliance. There are regional differences that prevent use of this term in defining standard applicability.**		
Occidental Chemical	Negative	3. The SDT discussed if MOD-026-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR. Do you agree with the proposal to not include the verification of synchronous condensers in MOD-026-1? YES Comments: Yes. There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Response: The SDT thanks you for your comment. The SDT agrees with your comment and understands both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.		
Manitoba Hydro (Greg Parent, S N Fernando, Daniel Prowse)	Negative	1)We disagree with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs, STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators.
Response: The SDT thanks you for your comment. The SDT agrees that in a technical sense generator and synchronous condenser excitation system testing have many similarities however there are several factors that prevent clear resolution of this issue. **Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review**		

Organization	Yes or No	Question 3 Comment
requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that: **a. With the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
MRO's NERC Standards Review Forum	No	Synchronous condensers are installed at locations where they are specifically needed for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.
Response: The SDT thanks you for your comment. **Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore the SDT has decided that:** **a. With the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
NERC Staff Review Team	No	It is most efficient to address synchronous condensers in the same project as generators given that

Organization	Yes or No	Question 3 Comment
		synchronous condensers have many of the same characteristics as generators. Static var compensators (SVCs) and static compensators (STATCOMs) are sufficiently different from generators and synchronous condensers to be appropriately covered in a separate SAR.Despite the low penetration of synchronous condensers in North America, these devices are most likely installed to extend a dynamic voltage security limit as noted by the drafting team. Due to the importance of these devices, validated models should be required for these devices similar to generators. Reliance on other motivations for equipment owners to validate models is inconsistent with requirements for generators and does not provide appropriate assurance that the equipment owners will validate models necessary for system reliability.

Response: The SDT thanks you for your comment. The SDT believes synchronous condenser model verification will need to be addressed by a standard and the remaining question is "Which standard should address this issue?"

Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that:

a. **With the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices which could be owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.**

b. **Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**

Organization	Yes or No	Question 3 Comment
Wisconsin Public Service Corp	No	Synchronous condensers are installed at where they are specifically for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.

Response: The SDT thanks you for your comment. The SDT believes synchronous condenser model verification will need to be addressed by a

Organization	Yes or No	Question 3 Comment
standard and the remaining question is "Which standard should address this issue?". Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that: a. With the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices which could be owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.		
Manitoba Hydro	No	Manitoba Hydro disagrees with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs, STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators.
Response: The SDT thanks you for your comment. The SDT agrees that in a technical sense generator and synchronous condenser excitation system testing have many similarities however there are several factors that prevent clear resolution of this issue. The SDT believes synchronous condenser model verification will need to be addressed by a standard and the remaining question is "Which standard should address this issue?" Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation		

Organization	Yes or No	Question 3 Comment
and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that: **a. With the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices which could be owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
Duke Energy	No	These types of reactive resources should be included if of a sufficient size to impact reliability.
Response: The SDT thanks you for your comment. The SDT agrees that in a technical sense generator and synchronous condenser excitation system testing have many similarities however there are several factors that prevent clear resolution of this issue. **The SDT believes synchronous condenser model verification will need to be addressed by a standard and the remaining question is "Which standard should address this issue? Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
Idaho Power - Power Production	No	
Imperial Irrigation District (IID)	Yes	THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Response: The SDT thanks you for your comment.		
BC Hydro and Power Authority	Yes	MOD-025 includes synchronous condensers. This doesn't appear to be consistent with the strategy for MOD-026?

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. It is true that synchronous condensers are included in the current draft of MOD-025. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit.		
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
SPP Reliability Standards Develpment Team	Yes	We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
Response: The SDT thanks you for your comment.		
Dynamics Review Subcommittee	Yes	It is good strategy to include synchronous condensers with other dynamic reactive devices as they all fall under the same category - providing dynamic reactive support.
Response: The SDT thanks you for your comment.		
Public Service Enterprise Group	Yes	The team needs to develop a consistent rationale on synchronous condensers in all of the standards being addressed in Project 2007-09. The team should consider asking the NERC Planning Committee to develop a white paper on the need (or lack of need) for synchronous condenser data.
Response: The SDT thanks you for your comment. Even though Project 2007-09 addresses 5 standards, only two of these standards address verification of generator dynamic models. **Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore the SDT has decided that:** **a. With the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		

Organization	Yes or No	Question 3 Comment
Southern Company	Yes	It is possible that the owners of the transmission system dynamic reactive devices (such as synchronous condensers, SVCs, STATCOMs, etc) may not be a NERC registered entity at all. Moreover, it is highly inappropriate to just add equipment not mentioned in the original SAR to the standard. It makes more sense, as SDT suggested, to have a separate SAR to address those transmission system dynamic reactive devices.
Response: The SDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	Yes. There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Response: The SDT thanks you for your comment. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.		
Ameren	Yes	Agree that there are relatively few synchronous condensers installed on the system. Including these devices with other dynamic reactive devices such as SVC's and STATCOMs, rather than in this standard, appears to be a good approach.
Response: The SDT thanks you for your comment.		
Consolidated Edison Co. of NY, Inc.	Yes	The inclusion of all reactive resources as BES Elements covered by a separate standard would be consistent with the current draft of the proposed Bulk Electric System (BES) Definition and Designations being proposed by the BES standard drafting team.
Response: The SDT thanks you for your comment.		
American Transmission Company	Yes	ATC believes that synchronous condensers may have significant impact in the areas where they are installed. Therefore, ATC agrees that they should be added to the NERC Compliance Registration Criteria and that a separate SAR should be established to develop a separate reliability standard for synchronous condensers and other dynamic reactive devices.
Response: The SDT thanks you for your comment.		
GE Energy	Yes	GE has no comment

Organization	Yes or No	Question 3 Comment
PPL Supply	Yes	
Bonneville Power Administration	Yes	
TVA - GO	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Luminant Power	Yes	
Progress Energy	Yes	
Westinghouse	Yes	
PacifiCorp	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Georgia Transmission Corporation	Yes	
Oncor Electric Delivery Company LLC	Yes	
Exelon	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 3 Comment
Dynegy Inc.	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
We Energies	Yes	
We Energies	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
US Army Corps of Engineers	Yes	
ISO New England Inc.	Yes	
Luminant Energy	Yes	
Southern California Edison Company	Yes	
American Electric Power	Yes	
RFC	Yes	
Tacoma Power	Yes	
PPL Electric Utilities	Yes	
ACES Power Members	Yes	
Electric Market Policy	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
Independent Electricity System Operator		We do not have an opinion on which standard should contain this as long as synchronous condensers are verified.

4. **Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain.**

Summary Consideration: As a result of industry comments regarding the SDT's request for questions or concerns that were not covered in the other questions, the SDT has made a number of modifications to the standard including:

1) **Correcting several VSL grammatical errors and ensuring consistency between the VSL "increment for tardiness" time period specified and the Requirement language.**
2) **An additional condition, row 12, was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service.**
3) **The format and column information of Attachment 1 has been revised for clarity.**
4) **The typographical errors in R2.1.1 language has been corrected to clearly state expectation that the unit model response matches the recorded response for a voltage excursion at the unit's point of interconnection from either a staged test or a measured system disturbance."**
5) **The language of R2.1.4 has been revised to align with the style of R2.1.6.**
6) **Several commenters expressed concern with the new Requirement R5 added to the standard giving the Planning Coordinator authority to require a model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. In addition, R5 language has been revised for clarity.**
7) **To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).**

8) There was some confusion regarding the treatment of small units at plants. The SDT modified the language in the Applicability / Facilities section for clarity and for consistency to the extent possible with the other draft standards in the Generation Verification effort.

9) As a reminder the SDT, in its response to industry comments, points out this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	Negative	We do not agree with the standard as posted, and we have cast a NO vote. We are unable to support the VRFs and VSLs for the standard/requirements that we reject, and we expect the standard to be materially revised which may result in corresponding changes to the VRFs and VSLs.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Sunflower Electric Power Corporation	Negative	We believe that changes are needed for the standard and thus the VSLs and VRFs will require conforming changes.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Southern Company Generation	Negative	VSL for R1 needs work - the requirement specifies 30 days - the VSL doesn't count it tardy until 90 days.
Response: The SDT thanks you for your comment. The SDT has corrected the discrepancy identified between Requirement R1 and the associated Lower VSL by changing R1 language to read "within 90 calendar days".		
Western Electricity Coordinating Council	Negative	The timeing requirements in the VSLs for R1 is not in agreement with the timing requirements for providing instructions in Requirement 1. Requirement 1 requires the Transmission Planner to provide instructions within 30 calendar days. However, the Lower VSL starts with a violation for providing the instructions more than 90 days lat but less than 120 days late. What about 31-90 days late. I believe the periods in the four VSLs should be adjusted to start with 31-60 for Lower, 61-90 for Moderate, etc. Other than this issue I support the proposed VRFs and VSLs.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. The SDT has corrected the discrepancy identified between Requirement R1 and the associated Lower VSL by changing R1 language to read "within 90 calendar days". The 90 calendar day's response period allows sufficient time for communication to occur between the Generator Owner, Transmission Planner and other entities (such as the software vendor or turbine manufacturer) with respect to obtaining information identified in requirement R1. Limiting the R1 response period to 30 days does not provide any benefit.		
MidAmerican Energy Co.	Negative	Neither the standard nor the VSLs are ready to be approved.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Liberty Electric Power LLC	Negative	Due to the need for changes to the underlying standard.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Texas Reliability Entity	Negative	(1) According to Requirement R1, the TP must provide instructions and data within 30 days of a request. The Lower VSL for R1 starts at 90 days - it should start at 31 days. (2) The Severe VSL for R2 is very awkwardly worded (triple negative?). (3) The VSLs don't reflect all of the actions required in the Requirements and in Attachment 1. For example, the R3 VSLs only refer to the 90 day initial response, and do not address the 365/180 day requirements set forth in the Attachment.
Response: The SDT thanks you for your comment. **(1) The SDT has corrected the discrepancy identified between Requirement R1 and the associated Lower VSL by changing R1 language to read "within 90 calendar days".** **The 90 calendar day's response period allows sufficient time for communication to occur between the Generator Owner, Transmission Planner and other entities (such as the software vendor or turbine manufacturer) with respect to obtaining information identified in requirement R1. Limiting the R1 response period to 30 days does not provide any benefit.** **(2) The SDT has revised the language for the R2 Severe VSL to eliminate the triple negative.** **(3) In the appropriate VSL statements for Requirement R2, reference language for periodicity timeframe has been revised to state, "periodicity timeframe specified in MOD-026 Attachment 1" in order to establish the proper linkage with the time requirements specified in Attachment 1.**		
Sacramento Municipal Utility District	Negative	This vote is cast to correspond with the position on the standard.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment.		
Indiana Municipal Power Agency	Negative	R4 is missing the VRF and Time Horizon. IMPA recommends “Lower” and “Long-term Planning”.
Response: The SDT thanks you for your comment. The SDT has added VRF and Time Horizon information to Requirement R4.		
Lakeland Electric	Negative	What does "external to the plant" mean as used in several of the requirements (e.g., R1, R2, and R6)? Considering R1, many generators have speed protection embedded in control systems (e.g., a GE Mark V or VI), is that included in footnote 1 to the requirement in the phrase: "multi-function protective devices or protective functions within excitation controls that directly trip or provide tripping signals to the generator based on frequency or voltage inputs"? In R2, does "voltage protective relaying" include station service protection, such as motor-contactors? The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment". R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" the output between minimum and maximum output of the generator implied? R4 is missing the VRF and Time Horizon - would recommend Lower and Long-term Planning.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
Liberty Electric Power LLC	Negative	This standard should be designed so that a TO needing the information initiates the process with a data request. There is no need to have the GO make the request and then have the TO respond - it adds an extra step and more risk of violation to no purpose.
Response: The SDT thanks you for your comment. The SDT assumes this comment refers to Requirement R1. R1 does not require the Generator Owner to make a request for information from the Transmission Planner. However, since several Generator Owners have expressed a need to obtain data possessed by the Transmission Planner, this requirement simply obligates the Transmission Planner to provide information to the Generator Owner if requested.		
Public Service Electric and Gas Co., PSEG Energy Resources & Trade LLC, PSEG Fossil LLC, Public Service Electric and Gas Co	Negative	This standard has made progress, but there are ambiguities that we addressed in our comments and which the team also addressed on its July 29 Webinar. We recommend that the standard incorporate the suggested comments and the team repost the standard for a round of comments only.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. The standard is being revised to resolve ambiguities and improve clarity. The SDT will consider incorporating suggested comments. The standard will be posted for comments once the revision process is complete.		
Muscatine Power & Water	Negative	The requirements in this Standards are onerous and burdensome for small Utilities, and we have concern about whether this Standard is cost effective for the industry. The transient stability dynamic modeling for excitation control was traditionally developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts required by this standard are expected to cost quite a bit to Generator Owners, especially for older units whose vendors/manufacturers may not even be in existence any more.
Response: The SDT thanks you for your comment. The SDT has tried to separate Transmission Owner and Generator Owner requirements. Many of the requirements are conditional and may not apply to some or all Generator Owner unit's. The SDT agrees there is a cost associated with this standard however, a need to verify excitation system models has been established and well understood by the technical community. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry. **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds believed to correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The standard does not require models to be valid over a wider bandwidth than what has been accomplished in the past.**		
Northern Indiana Public Service Co.	Negative	The related Standard Drafting subteams held a webinar on July 29 where they fielded numerous questions; issues still need to be addressed
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be		

Organization	Yes or No	Question 4 Comment
able to support the next posting of the standard.		
	Negative	The proposed standard is deficient in the following areas: I do not support verification exemptions for generating units rated 100 MVA and higher that have a capacity factor of less than 5%. These are the generating units that when dispatched, must be capable of synchronizing to the BES in a timely manner and operating reliably at their rated capability when synchronized to the grid. The proposed wording appears to allow generators to modify control and auxiliary system that would result in a change to the generating unit's capability and then notify the Transmission Planner of the change that has occurred. The order of notification and the actual modification of the generating unit is clearly backwards. The generator owner has a requirement to notify the Transmission Planner prior to modify the generating unit, especially if the modification results in a decrease in any aspect of the unit's capability (MW or MVAR) or its response time. The standard should include a requirement that all performance aspects of a machine Power System Stabilizer and limiter be made to responsible Transmission Planner. The proposed standard is not clear on this basic requirement.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Incremental model improvement for low capacity factor units does not justify the performance cost. This standard deals with modeling the generating unit and does not specify performance such as ability to synchronize in a timely manner for operating reliability. **Regarding changes to control and auxiliary systems, these changes do not affect the excitation system model nor does this standard address them. R4 only addresses changes to excitation control system and pant volt/var control system which will impact model accuracy.** **Regarding the last comment, this standard addresses model verification; in other words, this standard ensures that the model predicted response represents the actual response of the equipment. Per the SAR, this standard is a model verification standard and is not a performance standard.**		
National Association of Regulatory Utility Commissioners	Negative	The NPCC has identified the following issues that need to be resolved: Â· The standard allows for generators to change equipment and then notify the Transmission Planner of the change. This is unacceptable as it represents a significant reliability concern. Â· The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT Thanks you for your comment. Regarding your comment concerning equipment changes triggering model verification, this standard does not address providing notification of equipment changes or collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available. **Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes it is**		

Organization	Yes or No	Question 4 Comment
following the intent of the SAR in writing this standard as a model verification standard as opposed to a performance standard.		
Wisconsin Energy Corp.	Negative	Staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.
Response: The SDT thanks you for your comment. Staged testing does not require line switching; and instead simply requires injecting a step change signal value into the voltage regulator summing junction of the unit being tested. This testing has minimal impact on the transmission system and does not require transmission operator action.		
Dominion Resources Services, Dominion Virginia Power	Negative	Section 4.2.4 needs to be removed to be consistent with other standards. Section 2.1.1 “match” should be changed to approximate. The model will never exactly match. Section 2.1.6 remove “structure”. R3 bullet 3 “match” should be changed to approximate. The model will never exactly match. Attachment 1 title is missing “M”. Attachment 1 column “Condition” replace eleven and ten with “eleventh” and “tenth”. Section 4: Applicability should spell out testing exceptions
Response: The SDT thanks you for your comment. Section 4.2.4, as drafted, is necessary to identify applicable facilities covered by this standard. Note that the SDT added this Applicability to the draft standard after considering industry comments to the first posting noting concerns that the Applicability section is a subset of the Compliance Registry criteria. **Regarding comments pertaining to R2.1.1 and R3, the SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines match as something that is equal or similar to another.** **Regarding use of the term “structure” in Section 2.1.6, this language indicates that the “block diagram” is a necessary part of the information provided by the Generator Owner to the Transmission Planner. Note that the same term is also used in Section 2.1.4 as part of the description for the excitation control system and plant volt/var system.** **The typo in the Attachment 1 title has been corrected.** **Attachment 1 has been substantially revised for clarity and thus the issue with “eleven and ten” is no longer an issue in the current draft.** **The SDT believes that the Attachment 1 (Periodicity Table) is an appropriate document for specifying testing periodicity and exemption criteria.**		
Public Utility District No. 1 of Chelan County	Negative	Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements as identified in the WECC

Organization	Yes or No	Question 4 Comment
		Off-Nominal Load Shedding Plan must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
ISO New England, Inc.	Negative	Please see detailed commeents submitted. Of specific concern, we are voting negative due to: 1. The standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some areas. The applicable criterion should be as in the Compliance Registry. 2. The standard allows for generators to change equipment and then notify the Transmission Planner of the change. This is unacceptable as it represents a significant reliability concern. 3. The standard still is ambiguous and should contain further definitions and clarification 4. The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT Thanks you for your comment. (1) The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. While these units may be excluded from model verification, other standards still require that the data be supplied. **(2) Regarding your comment concerning equipment changes triggering model verification, this standard does not address providing notification of equipment changes or collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.** **(3) The standard is being revised to resolve ambiguities and improve clarity. The SDT will consider incorporating suggested comments. The standard will be posted for comments once the revision process is complete.** **(4) Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes such concerns are beyond the scope of this standard.**		
SERC Reliability Corporation	Negative	Please see coments of the SERC Dymanics Review Subcommittee.
Response: The SDT thanks you for your comment. Please see the SDT response to the SERC Dynamic Review Subcommittee comment.		
Northeast Utilities	Negative	Opposed with comments: 1) The standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that

Organization	Yes or No	Question 4 Comment
		would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some areas. The applicable criterion should be as in the Compliance Registry. 2) The standard allows for generators to change equipment and then notify the Transmission Planner of the change. This is unacceptable as it represents a significant reliability concern. 3) The standard still is ambiguous and should contain further definitions and clarification 4) The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT Thanks you for your comment. (1) The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. While these units may be excluded from model verification, other standards still require that the data be supplied. **(2) Regarding your comment concerning equipment changes triggering model verification, this standard does not address providing notification of equipment changes or collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.** **(3) The standard is being revised to resolve ambiguities and improve clarity. The SDT will consider incorporating suggested comments. The standard will be posted for comments once the revision process is complete.** **(4) Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes such concerns are beyond the scope of this standard.**		
Oncor Electric Delivery	Negative	Oncor Electric Delivery Company LLC believes that the reporting requirements for the generator owner as specified in R1, R2,R3,R4,R5 & R6 should be to the Planning Authority and not the Transmission Planner in the ERCOT Region. This would blend easily with the current ERCOT Protocols, ERCOT Operating Guides and ERCOT Planning Guide that require ERCOT to be the primary interface with Generation Resources. One option would be a regional variance that would point to the Planning Authority or Planning Coordinator in lieu of the Transmission Planner.
Response: The SDT thanks you for your comment. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. Since ERCOT is an exception, a regional variance can be considered. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.		
Nebraska Public Power District	Negative	NPPD supports the comments submitted by the Midwest Reliability Organization (MRO) NERC Standards Review Forum (NSRF).
Response: The SDT thanks you for your comment. Please see the SDT response to the MRO-NSFR.		

Organization	Yes or No	Question 4 Comment
Dominion Resources, Inc.	Negative	Dominion submits a negative ballot for the following reasons: Section 4.2.4 needs to be removed to be consistent with other standards. Section 2.1.1 “match” should be changed to approximate. The model will never exactly match. Section 2.1.6 remove “structure”. R3 bullet 3 “match” should be changed to approximate. The model will never exactly match. Attachment 1 title is missing “M”. Attachment 1 column “Condition” replace eleven and ten with “eleventh” and “tenth”. Section 4: Applicability should spell out testing exceptions
Response: The SDT thanks you for your comment. Section 4.2.4, as drafted, is necessary to identify applicable facilities covered by this standard. Note that the SDT added this Applicability to the draft standard after considering industry comments to the first posting noting concerns that the Applicability section is a subset of the Compliance Registry criteria. **Regarding comments pertaining to R2.1.1 and R3, the SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines match as something that is equal or similar to another.** **Regarding use of the term “structure” in Section 2.1.6, this language indicates that the “block diagram” is a necessary part of the information provided by the Generator Owner to the Transmission Planner. Note that the same term is also used in Section 2.1.4 as part of the description for the excitation control system and plant volt/var system.** **The typo in the Attachment 1 title has been corrected.** **Attachment 1 has been substantially revised for clarity and thus the issue with “eleven and ten” is no longer an issue in the current draft.The SDT believes that the Attachment 1 (Periodicity Table) is an appropriate document for specifying testing periodicity and exemption criteria.**		
Cowlitz County PUD	Negative	Cowlitz has concerns this Standard may prove too burdensome. For older generator units, it may prove nearly impossible to ever achieve models that will accurately predict actual generator response. However, the greatest stumbling point and reason for the negative vote is the low 75 MVA name plate applicability that appears to be arbitrary. Please present technical reasons why the Western Interconnection should be treated differently than other interconnections.
Response: The SDT thanks you for your comment. The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification. **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.**		

Organization	Yes or No	Question 4 Comment
Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds believed to correspond with at least 80% of the connected MVA in each Interconnection. As a result, the WECC MVA threshold to achieve 80% or more of the connected MVA in WECC for individual units and plants is 75 MVA. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		
Constellation Power Source Generation, Inc., Constellation Energy Commodities Group	Negative	Constellation Power Generation is voting negative on MOD-026-1 due to the vague language in Requirement 2.1.1. Constellation Power Generation would like the SDT to revisit this requirement with the knowledge that generation facilities do not have the necessary equipment to capture “the recorded response” of the excitation system and plant voltage/var controls to the level of granularity needed to demonstrate that it followed the “plant’s model response.” Further, generation facilities do not have the proper software to analyze the modeled response, and as such, cannot weigh that response against the recorded response should a facility have the necessary equipment to capture a response to a disturbance.
Response: The SDT thanks you for your comment. The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification. While it is true that many generators do not have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. Typically, the expert will install temporary recording equipment for testing.		
MidAmerican Energy Co.	Negative	Comment: Given the number and depth of comments at the NERC webinar, the NERC standard is not clear or enforceable. This will generate the need for interpretations and Compliance Application Notices which cause further confusion and enforcement issues. Technical issues are also present. There are concerns about the technical development and accuracy of current wind farm models. It is not certain that all manufacturers have fully developed all of the control system models necessary to meet these standards. Type III and Type IV PSS/E generic standard models have all been benchmarked. What has not been included in the these model are the wind farm park voltage controllers. While local turbine model controllers will dominate the short term response, the longer term park voltage controls are not represented. Therefore if the models aren’t available, then model traces can’t accurately match reality. Older wind farms or foreign manufacturers may not have appropriate models. In short, the state of wind

Organization	Yes or No	Question 4 Comment
		farm models hasn't completely developed to match wind farms and specific exemptions for wind farms need to be added to the standard at a minimum.

Response: The SDT thanks you for your comment. The SDT believes that required models have already been developed to an adequate level of detail, and are available in the planning tools. Generic models for VER have been developed in a collaborative industry effort (lead by the WECC Dynamic Modeling Working Groups) and should be validated in the absence of available OEM models. These generic models do include a provision for plant-level voltage control (performed by a plant volt/var management system). If plant voltage control is achieved by a device other than a volt/var management system (such as a STATCOM, SVC, etc), verification should also include models of these devices. Finally, An additional condition, row 12, was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service.

Organization	Yes or No	Question 4 Comment
Ameren Energy Marketing Co., Amerenue	Negative	Comment (1)The wording for Requirement 2.1.4 should be changed to read "Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator". Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment.(2)In Requirement R5, the term "technically justified request" needs to be clarified. (3)In Requirement R2.1.3, it should be clarified that "rotational inertia" should include all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself. (4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included.(5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators.(6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy.(7)The draft uses the term "Point of Interconnection" in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition.(8)Footnote 6 should be a set of sub-requirements for R4.(9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard.(10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote - it's too important in determining which generators must comply.

Response: The SDT thanks you for your comments.

(1) The SDT has revised R2.1.4 and has included the essence of your suggestion.

(2) The SDT has revised Requirement R5 using a footnote to define the phrase, "technically justified" as the simulated unit or plant response does not match measured unit or plant response.

Organization	Yes or No	Question 4 Comment
(3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft. **(4) The SDT is only proposing verification of units rated 20 MVA at plants which exceed the interconnection established MVA threshold (which is 100 MVA for the Eastern Interconnection). Even with the MVA threshold satisfied, units satisfying sister/proxy unit criteria will not have to be verified, further reducing the number of units actually tested.** **(5) The SDT believes sister/proxy unit criteria established is adequate.** **(6) MOD-012 and MOD-013 requires submission of the latest equipment dynamic model data. MOD-026 requires verification of the equipment dynamic model data.** **(7) Your observation regarding the phrase "point of interconnection" is correct. Please note that this phrase is not capitalized in the standard.** **(8) The SDT believes providing the list associated with Footnote 6 in the Requirement section would make the standard cumbersome to read.** **(9) The SDT believes that Section 6, since it addresses early compliance considerations, is important to require its own "section" in the standard.** **(10) The SDT believes providing the list associated with Footnote 2 in the main body of the standard would make the standard cumbersome to read.**		
Pacific Gas and Electric Company	Negative	As drafted, Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements as identified in the WECC Off-Nominal Load Shedding Plan must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. The language of Requirement R2, part 2.1.1 is confusing and needs to be clarified. We suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity included in MOD-026, Requirement R3.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
CPS Energy	Negative	Applicability should be for the "Generator Owner " and not the "Generator Operators".
Response: The SDT thanks you for your comment. The SDT agrees.		
Integrys Energy Group, Inc.	Negative	o While the Standard uses the word "verified" and "verification" loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be

Organization	Yes or No	Question 4 Comment
		determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for excitation control was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Response: The SDT thanks you for your comment. In response to your first question the SDT has drafted the standard with minimal technical specificity so that the actual mechanics of verifying the model could be left up to the experts. The SDT drafted a standard that concentrates on stating "what is required" but without stating "how to accomplish what is required". The standard also includes a peer review process. Based on industry comments, the present draft of the standard maintains this same philosophy. **Regarding your second comment, arbitrary large adjustment of model parameters without a valid technical reason is not appropriate. Minor adjustments to model parameters that are within expected tolerances may be appropriate.** **Regarding your third comment, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner.**		
Platte River Power Authority	Negative	o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage

Organization	Yes or No	Question 4 Comment
		relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. However language for zone 1 faults sets to remove the generator before 9-cycles. o Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? o The response content for R4 is ambiguous regarding what the written response should contain. o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping?
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
Occidental Chemical	Negative	4. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain. YES Comments: MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES voltage response - and have already the recording equipment needed to validate performance.
Response: The SDT thanks you for your comment. The SDT believes that the Generator Owner is in the best position to determine realistic and reasonable model representation of installed equipment. For this reason, the standard gives the Generator Owner authority to determine if the model adequately represents performance of installed equipment. It is not desirable to link this standard with the DME standard under development. Also, the DME standard applies to fault recorders and PMU equipment. Low resolution data is adequate for verification. The SDT agrees that if DME is already in place, especially if it is monitoring the appropriate quantities required for excitation control system verification, then it should be simpler to capture the required data for verification. The applicability section requires verification of units larger than the MVA threshold gross nameplate rating specified for each interconnection and this threshold is intended to emphasize the importance of modeling critical units.		
Manitoba Hydro (Greg Parent, S N Fernando, Daniel Prowse)	Negative	2)Attachment 1 is not clear. Specifically, -the "Condition" in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be 'verified' and serve as evidence for multiple units meeting the conditions listed. -the wording for the

Organization	Yes or No	Question 4 Comment
		allowance of a representative unit to be verified and submitted as evidence for identical units is not clear. -the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected ‘with the verified model’ which is incorrect. -We suggest the following. A statement that precedes the Attachment 1 table should be added that reads ‘For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ‘ Row 1 should then read ‘Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is = 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.’ 3)For Section 4.2 “Facilities”, the section should refer to ‘BES Generating Units and Facilities’ instead of restating components of the proposed BES definition.
Response: The SDT thanks you for your comment. The SDT has substantially revised Attachment 1. Regarding the last question, The SDT intentionally established the standard applicability as a subset of generators included in the NERC Registry Criteria. The term “BES Generating Units and Facilities” is not specific enough for compliance. There are regional differences that prevent use of this term in defining standard applicability.		
Santee Cooper (Terry Blackwell, James Poston, Lewis Pierce)	Negative	1) On “MOD-026 Attachment 1” under the “Periodicity” column, the method for model verification seems to be the analysis of a “recorded response for a voltage excursion”. It should be made clear that this excursion can be accomplished by either a staged test or a measured system disturbance. In some instances, it would be preferable to schedule staged tests with temporarily installed measurement and recording devices over permanently installing equipment to capture a response to a system disturbance. In each case, the goal of ensuring an accurate model will be accomplished. 2) At our generating facilities, it is very rare that voltage regulator or exciter parameters are changed. This generally occurs at periods much greater than ten years. Certainly, the model parameters must be confirmed after adjustment to any settings that would have an effect on the Volt/Var performance of the units. The accuracy of the model data would not be diminished by removing the ten year periodicity.
Response: The SDT thanks you for your comment. (1) The SDT has substantially revised Attachment 1.		

Organization	Yes or No	Question 4 Comment
(2) The SDT believes that a 10 year periodicity is appropriate to ensure there are not unforeseen modeling issues of actual equipment response to a voltage excursion that would necessitate revising the model for improving the accuracy of predicted equipment response. Also, the 10 year periodicity concept was overwhelmingly approved by industry (reference industry response to Question 2 comments for the first posting).		
Tenaska, Inc.	Negative	1) It is unclear whether such testing will lead to better models and improved reliability given all of the other assumptions made in stability studies 2) It is unclear whether a staged test or actual system disturbance or BOTH are required for “verification”.
Response: The SDT thanks you for your comment. The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification. **The Field Test confirmed model verification will result in accurate models.** **Either a staged test or actual system disturbance data can be used. Both are not required.**		
Ameren Services	Negative	(1)The wording for Requirement 2.1.4 should be changed to read “Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator”. Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment.(2)In Requirement R5, the term “technically justified request” needs to be clarified. (3)In Requirement R2.1.3, it should be clarified that “rotational inertia” should include all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself. (4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included.(5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators.(6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy.(7)The draft uses the term “Point of Interconnection” in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition.(8)Footnote 6 should be a set of sub-requirements for R4.(9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard.(10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote - it’s too important in determining which generators must comply.
Response: The SDT thanks you for your comments. **(1) The SDT has revised R2.1.4 and has included the essence of your suggestion.** **(2) The SDT has revised Requirement R5 using a footnote to define the phrase, “technically justified” as the simulated unit or plant response does not**		

Organization	Yes or No	Question 4 Comment
match measured unit or plant response. **(3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.** **(4) The SDT is only proposing verification of units rated 20 MVA at plants which exceed the interconnection established MVA threshold (which is 100 MVA for the Eastern Interconnection). Even with the MVA threshold satisfied, units satisfying sister/proxy unit criteria will not have to be verified, further reducing the number of units actually tested.** **(5) The SDT believes sister/proxy unit criteria established is adequate.** **(6) MOD-012 and MOD-013 requires submission of the latest equipment dynamic model data. MOD-026 requires verification of the equipment dynamic model data.** **(7) Your observation regarding the phrase "point of interconnection" is correct. Please note that this phrase is not capitalized in the standard.** **(8) The SDT believes providing the list associated with Footnote 6 in the Requirement section would make the standard cumbersome to read.** **(9) The SDT believes that Section 6, since it addresses early compliance considerations, is important to require its own "section" in the standard.** **(10) The SDT believes providing the list associated with Footnote 2 in the main body of the standard would make the standard cumbersome to read.**		
PacifiCorp	Negative	(1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage

Organization	Yes or No	Question 4 Comment
		limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditions within 95% and 105% of rated generator terminal voltage the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to PRC-024 Attachment 2. 2.1.3 Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" in PRC-024 Attachment 2. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2. (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. (5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. (6) PacifiCorp offers one comment on the Violation Severity Limits ("VSLs") proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements "unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3." However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation.

Organization	Yes or No	Question 4 Comment
		As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs. (7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
Imperial Irrigation District (IID)	No	
TVA - GO	No	
Arizona Public Service Company	No	
Luminant Power	No	
Progress Energy	No	
Westinghouse	No	
American Wind Energy Association	No	
Tri-State Generation and Transmission, Inc.	No	

Organization	Yes or No	Question 4 Comment
New York Power Authority	No	
Xcel Energy	No	
US Army Corps of Engineers	No	
Luminant Energy	No	
Tacoma Power	No	
GE Energy	No	GE has no comment for MOD-026
North Carolina Electric Membership Corp., Brazos Electric Power Cooperative, Southwest Transmission Cooperative	Affirmative	While we are voting affirmative for the VSLs and VRFs, conforming changes will be necessary if requirements are modified per our ballot comments.
Response: The SDT thanks you for your comments.		
Old Dominion Electric Coop.	Affirmative	Confirming changes need to be made to the VSL based on changes made in the standard itself.
Response: The SDT thanks you for your comments.		
ACES Power Members	Yes	This standard is highly administrative and full of compliance risks not associated with reliability. The purpose of the standard is to ensure that the GO provides an accurate model to the TP and ultimately to the PC. The requirements unnecessarily document the give and take that must occur between the GO and TP to produce a good model. R2, which essentially requires the GO to provide a good model, is the only requirement needed. Everything else is just documentation related and unnecessary.
Response: The SDT thanks you for your comments. The SDT agrees that R2 is the main requirement for improving reliability. The purpose of requirements R1, R3, R4, and R5 is to provide a peer review process to assure that the information provided per R2 is useful to the user of the information. There are always exceptions however others in the industry believe it is necessary to include these administrative requirements.		
BC Hydro and Power Authority	Yes	1. This standard is still not clear in terms of what constitutes verification of the model and what are related obligations of parties involved. Specifically, it is not logical or technically feasible to request GOs to

Organization	Yes or No	Question 4 Comment
		address any problems with "usability" that TPs may have with the excitation control system model applied in their simulation software. Related Requirements are R3 and R6. The GOs provide accurate model data of their systems during the generator interconnection and facility registration process. Detailed base-line testing is done at that time. For subsequent verifications, GOs would use certain software tools, most likely not the same that the TPs are using, to simulate excitation control system response. This simulated response would be compared with actual equipment response. If traces (signatures) match closely enough, the model is verified. The GO would submit required information to the TP as per R2. At this point, the GOs obligations should be over and subsequently, the GOs should not have a compliance obligation to take part in resolving any issues that the TP may have with the "usability" of their models. Any further involvement by the GOs should be in the spirit of good will and professional courtesy among the parties. In conclusion, GOs should not have compliance obligations to resolve issues related to "usability" of models applied in the TPs power system simulation tool. 2. The idea that GOs "own" the models and are responsible for model modifications and verification still remains controversial for a number of reasons:a. GOs have little need for models and many do not have any expertise in modelling.b. Software tools used by GOs or external consultants for commissioning and verification purposes would not be the same as the tools used by TPsc. TPs would have to work on tuning so the whole exercise would not have a particular value in a technical sense. This is supported by the NERC Event Analysis & Information Exchange staff who noted during the first comment period:"Although verification (not validation) of generator equipment settings and testing should be the responsibility of the GO, validation of generator models response to actual system events should be done by the Reliability Coordinator."Also, NERC's white paper "Power System Model Validation", Dec 2010, expands on this view. It implies that the ultimate responsibility for the usability and accuracy of dynamic models and how they perform in relation to the overall system model is the responsibility of the Transmission Planners, Reliability Coordinators or similar entities. 3. We recommend revising the wording in Requirement R2.1.1 for improved clarity. The way it is written, it strongly implies that the method of verification is based on system disturbance (ambient) monitoring: "Documentation demonstrating the unit or plant's model response matches the recorded response for a Voltage excursion at the generator or plant point of interconnection.4. Requirement 5 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner? Also, we recommend revising the wording in Requirement 5 for improved clarity.5. Attachment 1 Column 6 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner?

Response: The SDT thanks you for your comment. Regarding your first comment, the SDT believes that model verification has to be a collaborative effort between the Generator Owner and the Transmission Planner. As owner of the model, the standard is drafted such that the Generator Owner has the final word when collaborating with the Transmission Planner. If the Generator Owner cannot resolve the model "usability" issue, with the Transmission Planners dynamic simulation software, then the Generator Owner simply communicates this fact to the Transmission Planner.

Regarding your second comment, the industry affirmed with the first posting of the draft standard that the Generator Owner should be assigned responsibility for the model. The Generator Owner has direct access to the equipment. The Transmission Planner has the simulation software, but

Organization	Yes or No	Question 4 Comment
does not typically have access to the equipment or have testing capabilities. Therefore, the standard includes several Requirements that facilitate interaction between the Generator Owner and the Transmission Planner. **Regarding your third comment, Requirement R2.1.1 has been revised for clarity. Standard references to the Planning Coordinator are correct. The Planning Coordinator was chosen after considering industry comments to the first posting of the draft standard to require a higher level of justification for requesting a model review for a unit not listed in the Applicability section than simply contacting the generator owner.**		
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
Response: The SDT thanks you for your comment.		
Idaho Power – Power Production	Yes	The Requirements direct the GO to send responses, data, inquiry to the Transmission Planner. Should this really be to the Transmission Operator? We understand that the TP will ultimately use the data, however, we believe the data and communications should flow through the TOP.Specifying timeframes for both recording data and providing results is cumbersome. More properly, timeframes and periodicity should be specified only on providing results. If necessary, a limit on the age of the recorded data could be specified.R6.1, R6.2 and R6.3 seems overly prescriptive and of little value. In the process of verifying model data and comparing to recorded results, those 3 conditions are met. If the Transmission Planner has concern about their ability to use the model data in their studies, it is more properly addressed either without specific criteria, or with the specific criteria that the Transmission Planner is unable to reproduce the simulated response contained in the model verification.The requirement of several responses to submit plans to test within 365 days and submit with 180 days (per the periodicity table) seems too long from an system reliability standpoint, particularly where it is the outcome of an observed response to an actual event not matching the predicted response. On the other hand, scheduling a test and model verification within a shorter period of time would be challenging for the GO, particularly those that rely on outside contractors for the model verification work.Any request to verify or retest due to an observed response not matching an actual event should be accompanied by full electronic information (recorded data, simulated output, simulation conditions, model data used by TP).Requirement R1. The first two bullets appear to allow variation between Transmission Planners on acceptable models and software. The list of acceptable models needs to standardized at least across the RRO. In addition, the GO should not need to adjust the model validation and verification work based on the software that the TP uses (what happens when the TP uses multiple software packages?). If the SDT feels there is a need to specify acceptable software, then that should also be standardized. The third bullet should read "All of the Generator Owner's existing" instead of "Any". The TP should provide all the information in its database regarding the GO's facilities, not just "any" piece of it.R2, 2.1. Reference to "models acceptable to its Transmission Planner" is inappropriate, see previous comment. The list of acceptable models needs to be standardized, although

Organization	Yes or No	Question 4 Comment
		situations (rare) where the Generator Owner and Transmission Planner jointly agree to use a model not on the list should be allowed. In particular, the Transmission Planner should not restrict use of any the models on the standardized acceptable list.

Response: The SDT thanks you for your comment. Regarding your first comment, the SDT selected the Transmission Planner to be the single point of communication for model verification issues. The reason for this is that the Transmission Planner maintains the dynamic database used to performed stability assessments that define BES security boundaries.

Regarding your 2nd comment, Attachment 1 specifies that the final model verification has to be provided either 180 or 365 days after the response of the equipment is captured. The SDT believes that this specificity is required in order to ensure a ten year (or less in some scenarios) periodicity.

Regarding your 3rd comment, the Generator Owner is responsible for verifying the recorded equipment response matches the model's predicted response. The Transmission Planner is only responsible for determining if the model is usable.

Regarding your 4th comment, the SDT expects the Transmission Planner and Generator Owner to work together to resolve any issues with the model. The SDT believes that both entities have common motivation to resolve modeling issues and will share relevant technical data.

Regarding your 5th comment, standardizing a list for the RRO is not possible since Transmission Planners within an RRO may utilize different dynamic simulation software packages.

Regarding your 6th comment, the standard is not written to require use of a specific software package.

Regarding your 7th comment, the word "any" is meant to mean that any unit data can be requested. Once a particular unit's data is requested, the Transmission Planner is required to provide the complete dataset associated with that unit's excitation control system and plant volt/var control model.

Regarding your 8th comment, the Transmission Planner has to maintain a list of acceptable models to ensure that the Generator Owner will not supply a model that is not supported by the Transmission Planners' dynamic simulation software.

Organization	Yes or No	Question 4 Comment
SPP Reliability Standards Develpment Team	Yes	The applicability of 100 MVA matches MOD027-1 but is inconsistent with MOD025-2 or PRC 019-1. We feel like these should be consistent in every standard included in this project. VSLs for R4 footnote reference needs to be deleted since there is no footnote to reference. We would like to see a more consistent approach to the comment forms and the standard itself. It seems there is room for clean up in the posted standard/comment form.

Response: The SDT thanks you for your comment. The Applicability of MOD-026 and MOD-027 is unique because these are the only standards addressing dynamic model verification. The VSL footnote appears earlier in the standard. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.

The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits

Organization	Yes or No	Question 4 Comment
determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification. **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds believed to correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT has revised the standard in response to industry comments and hope clean up performed is adequate.**		
MRO's NERC Standards Review Forum	Yes	We have a number of questions and concerns as follows: o It is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? o We have concern about whether this Standard is cost effective for the industry. The transient stability dynamic modeling for excitation control was traditionally developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts required by this standard are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more. o MOD-026 does not account appropriately for the differences between distributed generation and single shaft generation. Aggregate generation that do not have a common excitation and regulator control system (such as wind farms) may pose serious difficulties in meeting system disturbance and / or staged testing. A staged test can be performed for a single shaft unit. However, wind farms may not have a centralized plant or wind farm voltage controller. If that isn't the case, entities may be forced to actually shock the BES to force a disturbance large enough to force a wind farm response. If this is true, then exceptions need to be made. o In addition, there are concerns about the technical development and accuracy of current wind farm models. It is not certain that all manufacturers have fully developed all of the control system models necessary to meet these standards. Type III and Type IV PSS/E generic standard models have all been benchmarked. What has not been

Organization	Yes or No	Question 4 Comment
		included in these models are the wind farm park voltage controllers. While local turbine model controllers will dominate the short term response, the longer term park voltage controls are not represented. Therefore if the models aren't available, then model traces can't accurately match reality. Older wind farms will not have appropriate models. In short, the state of wind farm models hasn't completely developed to match wind farms and specific exemptions for wind farms need to be added to the standard at a minimum.

Response: The SDT thanks you for your comment. In response to your first question, the SDT has drafted the standard with minimal technical specificity so that the actual mechanics of verifying the model is left to the experts. The SDT drafted a standard that states "what is required" without stating "how to accomplish what is required". This standard also includes a peer review process. Based on industry comments, the present draft of the standard maintains this same philosophy.

Regarding your second comment, arbitrary large adjustment of model parameters without a valid technical reason is not appropriate. Minor adjustments to model parameters that are within expected tolerances may be appropriate.

Regarding your third comment, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner.

Regarding your fourth comment on distributed generators in a plant (such as a Wind Plant), it is reasonable to expect a small signal disturbance (such as switching a static var bank or changing the tap on a load tap changing transformer) test be performed to exercise response of the plant volt/var controls so data recording can be accomplished for validation efforts. The magnitude of the test disturbance will be determined by the nature of the plant control system type (linear closed-loop or semi-discreet with deadband) installed. The specific nature of the stimulus applied is application dependent and will need to be determined by the validation expert, taking into account availability of devices, system strength and other conditions during the test. However, none of these techniques will adversely impact BES reliability.

Regarding your final comment on availability of VER plant-level models, Generic models for VER have been developed in a collaborative industry effort (lead by the WECC Dynamic Modeling Working Group) and should be validated if an OEM model is not available. These generic models include provision for plant-level voltage control using a plant volt/var management system. If plant voltage control is achieved by a device other than a volt/var management system (such as a STATCOM, SVC, etc.), verification should also include the models for these devices.

Electric Market Policy	Yes	Dominion suggests:MOD-026 Section 4.2.4 needs to be removed to be consistent with other standards.MOD-026 Section 2.1.1 "match" should be changed to approximate. The model will never exactly match.MOD-026 Section 2.1.6 remove "structure".MOD-026 R3 bullet 3 "match" should be changed to approximate. The model will never exactly match.MOD-026 Attachment 1 title is missing "M".MOD-026 Attachment 1 column "Condition" replace eleven and ten with "eleventh" and "tenth".MOD-

Organization	Yes or No	Question 4 Comment
		026 Section 4: Applicability should spell out testing exceptions.
Response: The SDT thanks you for your comment. Section 4.2.4, as drafted, is necessary to identify applicable facilities covered by this standard. Note that the SDT added this Applicability to the draft standard after considering industry comments to the first posting noting concerns that the Applicability section is a subset of the Compliance Registry criteria. **Regarding comments pertaining to R2.1.1 and R3, the SDT believes use of the term "match" is appropriate because the Webster's dictionary defines match as something that is equal or similar to another.** **Regarding use of the term "structure" in Section 2.1.6, this language indicates that the "block diagram" is a necessary part of the information provided by the Generator Owner to the Transmission Planner. Note that the same term is also used in Section 2.1.4 as part of the description for the excitation control system and plant volt/var system.** **The typo in the Attachment 1 title has been corrected.** **Attachment 1 has been substantially revised for clarity and thus the issue with "eleven and ten" is no longer an issue in the current draft.** **The SDT believes that the Attachment 1 (Periodicity Table) is an appropriate document for specifying testing periodicity and exemption criteria.**		
Dynamics Review Subcommittee	Yes	R2: The wording for Part 2.1.4 makes it seem that the required model structure and data only applies to the voltage regulator portion of the excitation system. The DRS recommends that R 2.1.4 be reworded to:"Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator." R5: A "technically justified request" needs to be clarified. We suggest using words similar to those used in the slides associated with this project: "A technical justification that demonstrates, through simulation and/or measured response, that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response."R2.1.3 : The DRS recommends a clarification to "rotational inertia." Please consider the following wording: "Generator (or plant equivalent) model structure and data (such as reactance, time constants, saturation factors, rotational inertia (including all rotating components), or equivalent data)."
Response: The SDT thanks you for your comments. **(1) The SDT has revised R2.1.4 including the essence of your suggestion.** **(2) The SDT has revised Requirement R5 using a footnote to define the phrase, "technically justified" as the simulated unit or plant response does not match measured unit or plant response.** **(3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.**		
LG&E and KU Energy	Yes	Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. LG&E

Organization	Yes or No	Question 4 Comment
		and KU Energy suggests tha the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.
Response: The SDT thanks you for your comment. The SDT believes it is better for industry to have 180 days to perform model verification activities in lieu of establishing a universal 90 day period to perform all activities required just to achieve timeframe consistency among the Requirements.		
FirstEnergy	Yes	FirstEnergy provides the following additional comments and suggestions:1. Unfortunately as written this standard may require Generator Owners to purchase software to properly analyze voltage excursions to verify their models. This level of expertise historically existed with the TO/TOP, not the Generator. It will be very difficult for the Generators to develop and maintain this expertise for a verification that will only be run once every 10 years. Also, if additional instrumentation is needed to capture this data, nuclear fleets may be challenged to ensure at least 30% of their applicable units will comply with R2 based on refuel outage schedules.2. Applicability Section 4.2.4 - We do not agree with the Planning Coordinator being able to include additional units. Even though the standard says that the PC would have to show technical justification, it should not be left to their discretion to add an entity's unit as applicable. A regional entity is the only ultimate authority that can make this decision and the PC should go through its Regional Entity to prove this justification. We suggest removing this section. Furthermore, it states that the technical justification would need to be verified. It is not clear who would make this judgment on the validity of the justification.3. We are not clear as to what the standard is referring to when it mentions "volt/var control". 4. In requirement 2.1.1, of R2 it states"2.1.1. Documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance."The SDT should specify the magnitude of the voltage excursion referenced in this section.5. In the SDT notes they make reference to allowance being given for identical (Sister) units but I did not see it anywhere in the standard. Can Generator Owners take credit for Sister units when supplying the model verification? 6. As a general note, the first draft of this standard was reviewed by industry over 2 years ago. It seems like a long time between drafts to expect the industry to review and vote on a standard given that there may be several new personnel in a company that are new to compliance. I would have hoped the team came out with only a comment period at this time.7. Attachment 1 - General Comment - "M" is missing from title of attachment "OD-026 Attachment. Also. We assume that the mentioned "voltage excursion" is in reference to the proposed definition found in the proposed PRC-024-1. If so, it should be capitalized and added to the front of the standard and balloted with the standard.
Response: The SDT thanks you for your comment. The responses below are numbered to match the comments. **1. The standard has been written so that either ambient monitoring or a staged testing can be used. The Generator Owner is not required to have the same software used by the TO/TOP. Also, the Generator Owner is not required to maintain testing expertise. It is a Generator Owner decision to**		

Organization	Yes or No	Question 4 Comment
maintain testing expertise or hire a consultant (which could include personnel from its Transmission Planner). A staged test typically involves injecting a step change signal into the voltage regulator. Permanent instrumentation/equipment is not required to be installed for staged testing. A laptop PC can be used to record staged testing data. Nuclear units do not need to wait until a refueling outage to accomplish this test. **2. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.** **3. Volt/Var control refers to voltage or var output control at a common coupling point for an entire plant consisting of multiple units, typically comprised of technology that, by itself, does not contain sufficient dynamic var capability (such as wind/solar plants).** **4. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Typically a 1% - 2% voltage excursion will provide adequate results.** **5. Yes, sister unit consideration is included in the Periodicity Table (Attachment 1).** **6. The standard has been revised significantly in response to industry comments and has been sent to ballot to gage the level of industry support existing.** **7. The attachment title has been corrected. The phrase, "voltage excursion" is not a defined term, and does not relate to PRC-024.**		
Public Service Enterprise Group	Yes	1. The capacity factor calculation referenced in 4.2 should refer to a future attachment that the team would develop that explains (a) which reliability standard one would use to for a unit's capacity rating (such as MOD-010) for the calculation and (b) a sample calculation.2. In 4.2.4, the sentence "Any technically justified unit requested by the Planning Coordinator" should specify (a) the entities that may develop the technical justification, (b) the entity who will evaluate that technical justification and (c) the criteria for judging whether an excluded unit should be included.3. In R1, first bullet: a. Would the instructions issued by the Transmission Planner on "on how to obtain the list of acceptable excitation control system and plant volt/var control function model for use in dynamic simulation" cover "acceptable" verification via staged tests and "acceptable" verification by a measured system disturbance per R2.1.1.b. Are Transmission Planners the appropriate entity to determine "acceptability" of models or verification since there are about 120 Transmission Planners registered in the Eastern Interconnection? See the comment below regarding R2.1.14. R2.1.1 addresses verification via either staged tests or a measured system disturbance. However, the standard leaves the judgment of the acceptability of verification performed by a GO to the Transmission Planner. We suggest that the team include an attachment to the standard that provides

Organization	Yes or No	Question 4 Comment
		guidance for how to perform acceptable verification, covering both staged testing and a measured system disturbance.5. R5 is unclear. For example, does the 90-day submission period in 5.1 address submissions under 5.2 and 5.3, or does it require that the GO merely acknowledge receipt of the request within 90 days? Since 5.2 addresses plans to verify a model, why would "corrected" data in 5.3 be due within 90 days? 6. Both R3 and R5 require GO action in response to a notification by a Transmission Planner (R3) or a Planning Coordinator (R5). Can a Transmission Planner or Planning Coordinator require a response from a GO for generators that are not yet verified by the GO per the timetable in section 5? If not, it appears that R3 and R5 should be rewritten to recognize this limitation. 7. The July 29 webinar made clear that generator exciter model verification applies to synchronous generators and the plant volt/var control function applies to non-synchronous generators. It would be helpful if this clarification was made in the standard itself, perhaps in the purpose statement.

Response: The SDT thanks you for your comment. The responses below are numbered to match the comments.

1 To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).

2. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.

3. a) The list of acceptable models is simply the type of models that the Transmission Planner will accept. This has nothing to do with the methodology used for recording the plant response to a voltage excursion.

3. b) The SDT believes the Transmission Planner is the appropriate entity.

4. Either the staged test or the ambient test can be used to verify the model. The Generator Operator decides which test is used. Restating for emphasis, the list of acceptable models identified in R1 is the list of model structures that can be used to perform the model verification process and does not address "acceptable methodologies" for performing the model verification.

5. After considering industry comments, the SDT has revised R5 for clarity.

6. No, neither the Transmission Planner nor the Planning Coordinator can invoke Requirement R3 for a unit that has not been verified. Requirement R5 is meant to address units otherwise excluded from the standard Applicability standard; so the Transmission Planner or Planning Coordinator can request model verification for otherwise excluded units.

Organization	Yes or No	Question 4 Comment
7. Plant volt/var controls include plant voltage control systems and/or dynamic var devices other than conventional generators. For example, these types of control systems could apply to wind farm units. Wind farm units include both synchronous and asynchronous (often associated with Type I generic models) units. As such, plant volt/var control can be applied to plants that contain synchronous generators, non-synchronous generators, or a combination of both.		
PPL Supply	Yes	1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word "software;" and para. R2.1.1 should state that "Verification consists of developing one or more models that collectively include the following information:"The present R2.1.1 text, "acceptable to the Transmission Planner," is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO's first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified status only after being accepted by the Transmission Planner, the term "verified model(s)" in the R2 Violation Severity Levels should be replaced with, "initial submittal of proposed-verified model(s)". 3. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in para. R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026.4. The definition of a "technically justified request" in para. R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.
Response: The SDT thanks you for your comment. **Regarding your first comment, the SDT believes it is better for industry to have 180 days to perform model verification activities in lieu of establishing a universal 90 day period to perform all activities required just to achieve timeframe consistency among the Requirements.** **Regarding Comment 2, the SDT has revised verbiage in Part 2.1 to emphasis the end goal of verifying the model. The SDT also points out that**		

Organization	Yes or No	Question 4 Comment
standard language proposed is for facilitating verification of the dynamic model, and not development of the dynamic model. **Regarding Comment 3, the standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model. It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response. The Generator Owner should not be concerned with "acceptance criteria" proposed by a transmission entity.** **Regarding Comment 4, the "technical justification" is not related to Requirements R6.1 – R6.3. These requirements only address if the model is useable by integrating successfully into the Transmission Planner's dynamic simulation software. Additionally, several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.** **Regarding Comment 5, the "walk down" to correct model parameters could be as simple as identifying in the field that equipment gain or limit setting values are incorrectly represented in the model.**		
Florida Municipal Power Agency	Yes	FMPA appreciates the efforts of the SDT to "right-size" the applicability to plants that truly impact the stability response of the system. However, the words used in the draft standard allow a loop-hole to the SDT's intent. Footnote 4 to the Applicability section states: "(a) technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response". If a region wishes to include 1 MW generators in the process, all they have to do is show that the unit's actual response does not match the simulated response without a technical justification to show that the 1MW generator has any impact on the actual stability response of the system. The SDT should change the "or" in footnote 4 to "and" meaning that the technical justification needs to include both an impact to a stability limit AND a difference between actual and simulated response.In addition, for R5 and footnote 4, who judges what is and what is not a "technical justification"? For instance, NPCC in their regional UFLS standard proposed to cause 1 MW generators to register and be included in the standards. Does the region have the final say on technical justification?The staged test in R2.1.2 and Attachment 1 that is required if an actual event does not occur is onerous. FMPA believes

Organization	Yes or No	Question 4 Comment
		this “staged test” is impractical and should be eliminated. Within a ten year period, an actual event is likely to occur resulting in a recorded response. If an actual event does not occur, then, the risk of inaccuracy is small and a “staged test” with associated higher risk should not be required to only marginally improve accuracy.

Response: The SDT thanks you for your comment. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review.

Regarding acceptable methods for capturing equipment response to a voltage excursion, either ambient event data or staged testing is acceptable. When performing staged testing typically a 1% – 2% step change in the voltage reference signal is used (even with the unit synchronized to the BES) and this is widely accepted safe industry practice.

Organization	Yes or No	Question 4 Comment
NERC Staff Review Team	Yes	Validation of the voltage and reactive power response of generating units for significant system disturbances indicates that the dynamics database quality is not as robust as noted in the Background Information posted with this standard. As a result NERC staff offers the following three specific comments for improving the quality of the model database:1) It is not possible to accurately model system voltage and reactive power response with valid models for only 80 percent of the installed system capacity. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per the SDT estimates this will assure accurate modeling for approximately 95 percent of installed capacity.2) We disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions when reactive support may be most critical thereby making valid models critical to system reliability during those conditions. While they should not be exempted from the standard, we do believe it may be appropriate to assign these units lower priority in the implementation plan.3) The initial completion of validation for all applicable units and periodicity for model verification should be 5 years, not 10 years. The 10 year time is excessive.Any Functional Model entity that requires the models, including Planning Coordinators, Transmission Operators, and Reliability Coordinators, should be permitted under Requirement R3 to provide notification to the Generator Owner that the model is not usable or that the predicted response did not match the recorded response to a transmission system event. Also, Requirement R3 should permit entities to notify the Generator Owner that the model is not usable for any

Organization	Yes or No	Question 4 Comment
		reason. We recommend removing the list referencing Requirement R6, parts 6.1 through 6.3, because it is not and cannot be an all-inclusive list of problems that could make the model not usable (e.g., the model could cause the simulation software to “freeze”).In the first row of the Periodicity Table, transmission of the verified model and documentation to the Transmission Planner should occur within 180 days from the date the recorded response is collected similar to all other rows in the table. There is no apparent basis for the additional time provided in the first row of the table.The violation risk factors associated with Requirements R1 through R6 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system.The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R6 should include the operations planning horizon.In Requirement R6, part 6.2, the reference to negligible transients is not measurable. We recommend modifying this to “. . . results in a response that varies less than the numerical stability of the program used for the simulation.”In Requirement R6, part 6.3, the introductory phrase “For an otherwise stable simulation” is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with “A disturbance simulation results in . . .”The SDT should consider use of the word validation instead of verification and assure that the terms used in this standard are consistent with other standards.

Response: The SDT thanks you for your comment. Regarding your opening statement and Comment 1, although the standard does not require verification of modeled excitation control system and plant volt/var response for all units/plants smaller than the MVA nameplate rating thresholds listed in the Applicability section, it is expected that provided models are accurate. If there are reasons to believe that a unit which does not meet the Applicability criteria does not have an adequate model, there is a process proposed that requires the Generator Owner to review the model, and possibly model verification if the review does not identify why the model is not able to correctly predict equipment response.

Regarding Comment 2, the SDT believes requiring verification of small size MVA units and units with a low (< 5%) capacity factor is not practical and would deplete the industry’s limited verification capability for very little reliability benefit as concluded from the field testing data involving 4 regions (WECC, SERC, ERCOT, and the FRCC) initiated by the NERC Phase III-IV SDT and completed July 2007. Units with low capacity factor would seldom be synchronized to the BES during significant events.

Regarding Comment 3, the SDT believes the 10 year period is adequate for both initial verification and repeat verification given that the standard also specifies verification is required when equipment changes are made that would affect the units’ excitation control system response.

Regarding Comment 4, the SDT believes that the single point of contact for model issues detailed in Requirement 3 is correctly identified as the Transmission Planner. It is not reasonable to make the Generator Owner interact with several Functional Model Entities when only one interaction, specifically the Transmission Planner, is necessary. Also, the second bullet paragraph of R3 (…identifying technical concerns with the verification documentation related to the excitation control system and plant volt/var control1 system function model…) allows the Transmission Planner to

Organization	Yes or No	Question 4 Comment
request the Generator Owner provide a response for all reasonable modeling issues that can occur. **Regarding Comment 5, the SDT points out that if any of the Requirement 6 Parts are not achievable, resulting in "software freezing" or countless other issues, then the Transmission Planner will determine that the model is not usable. In other words, the cause of the issue does not matter. What matters is the model does not function correctly to satisfy each of the three tests specified.** **Regarding Comment 6, the reason why the SDT is proposing additional time is because this condition is the one which will recur during the normal, ten year model verification cycle. There is no reason to suspect that the model parameters will need significant adjustment since the last verification performed. The SDT believes that allowing sufficient time to make sure that the last yet critical step of model verification (which is refining the model to make sure that predicted response matches the actual response of the equipment) is performed correctly.** **Regarding Comment 7, the SDT has changed the VRF for R2 and R6 from low to medium. R1 is administrative in nature in making sure that that the Generator Owner has access to data needed to perform model verification per R2. R3 is an administrative peer review requirement. R4 and R5 are also administrative in defining the processes in which a Generator Owner communicates with a transmission entity to either provide updated model data or to commit to verifying the model per R2.** **Regarding Comment 8, since model verification activities typically take months, if not years to perform, the time horizon of "Long Term Planning" is appropriate.** **Regarding Comment 9, the SDT is not aware of any industry practice that takes into account the numerical stability of the simulation program. It is left to the judgment of the expert reviewing the study results to determine if the transients identified are negligible.** **Regarding Comment 10, utilizing a stable simulation is necessary for determining if the model will adversely impact the robustness of any dynamic modeling performed. If an unstable simulation is used as basis, then there is no way to determine the additional negative response of the model when assessing usability.** **Regarding Comment 11, the SDT believes the term "verification" is an appropriate term. The word verify means, "to determine or test the accuracy of" whereas verification means "the act of verifying". Also, since this term is not capitalized, the context does not have to be exactly relevant to other standards.**		
Bonneville Power Administration	Yes	MOD-026: By making Transmission Planners responsible for generator verification instead of regional entities, it may be more difficult to produce integrated regional models.The standard should also apply to Regional Coordinators to ensure consistent generator verification requirements within regions.
Response: The SDT thanks you for your comment. Integrated regional models have been constructed for quite some time with a large number of participants submitting dynamic models. Because this standard will result in enhancing the validity of dynamic models, the SDT believes that this standard will actually enhance the process of creating integrated regional dynamic databases and load flows.		
Westar Energy	Yes	The applicability in this standard (â‰¥100 MVA) is consistent with the applicability in MOD-027-1. However, the applicability in this standard is not consistent with MOD-025-2 and PRC-019-1. We propose

Organization	Yes or No	Question 4 Comment
		that the SDT revise the applicability to be consistent between all of the standards included in this project.

Response: The SDT thanks you for your comment. The Applicability of MOD-026 and MOD-027 is unique because these are the only standards addressing generator dynamic model verification. Therefore, the SDT believes that consistency between the Applicability Sections of these two standards make sense. The SDT also thought it best not to force the Applicability to be the same in the other standards that address distinctly different subject matter.

Organization	Yes or No	Question 4 Comment
Southern Company	Yes	1) We question how field tests can be performed on aggregation based facilities. We recommend removing the requirement for developing models for the aggregation of units < 20 MVA for conventional units. 2) Isn't R2.1.3 already required of the GO in MOD-012 (dynamic data on generators) 3) The timing of R5 requirement (90 days) seems to contradict with the schedule for modeling in Attachment 1 (1 1/2 years) for PC initiated model reviews. 4) The background section indicates that the PC can request a unit not in the applicability scope (page 2, last paragraph), but R5 doesn't say this. The wording on R5 indicates that the PC can request a review of an existing model. 5) Attachment 1 is difficult to use. Please cross reference the requirement that goes with each row of the periodicity table Attachment 1. Please add row numbers to the table. Please use column 1 to briefly label the conditions that controls the applibility of the row (for example - the row including the exceptions could be labeled SISTER UNITS) 6) It is suggested to review the order in which the requirements are currently numbered. The current R3 seems to be out of place (should occur after the requirement that is currently R6). This will more closely match the flow of how the process will work. 7) VSL for R1 needs work - the requirement specifies 30 days - the VSL doesn't count it tardy until 90 days. 8) The Sister concept needs to be mentioned in the applicability section 9) The exception rule in Attachment 1 should include Sister units at different geographic sites in addition to those at the same site. 10) The exception rule in Attachment 1 should not be limited to 350MVA - if units are identical, then the sister concept should apply. 11) The first bullet of R1 needs to make "model" plural ("models") for the grammer to be correct.12) As the requirement of R4 is not a response to a request, we suggest changing the wording of the text in M4 from "show that it provided a written response (...) submitted within 180" to "show that it submitted communication (...) within 180", where (...) is shown to indicate no change to the parenthetical element.13) As requirement R6 is an evaluation of the verified model by the TP, we suggest changing the wording of the text in R6 from "show that it provided a written response" to "show that it provided an evaulation of the submitted model".

Response: The SDT thanks you for your comment. The responses below are numbered to match the comments.

1. **The SDT agrees with this point and has modified the language that inadvertently indicated that mixed plants containing conventional units less than 20MVA had to be tested as an aggregate. The language has been modified to allow, but not require, aggregation by type. This can be accomplished by verifying one unit, then utilizing the sister/proxy unit consideration specified in Attachment 1 for the remaining units of the same type. However, as an option if technically feasible, units can still be tested as an aggregate.**

Organization	Yes or No	Question 4 Comment
		2. The SDT is requiring the Generator Owner to include in the model verification documentation submitted to the Transmission Planner the generator model information, including the model structure and data that was used for verifying the excitation control system (which is a closed loop system). **3. The language in Section 5.1 has been revised for clarity.** **4. The SDT revised the language of R5 to make it clear that the Planning Coordinator, with technical justification, can specify a unit for model review that is not listed in the Applicability Section.** **5. The SDT added applicable Requirement references to the conditions identified in Attachment 1. The SDT believes these additions are sufficient. It should be noted that the use of the terms "sister" or "proxy" unit has deliberately been avoided in the standard since this language is considered "folksy".** **6. The SDT recognizes that the sequencing of the Requirements to the degree that is necessary for any particular unit model is subjective. The SDT believes the current order of standard Requirements is reasonable.** **7. The VSL's have been revised for consistency.** **8. The sister unit concept is more appropriate to include in the Attachment 1 (Periodicity Table) since it is an exemption that can be utilized by the Generator Owner.** **9. The SDT respectfully asserts that the "same physical location" requirement is necessary since this language provides a strong indication of equipment and settings similarity (which can be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in different geographic locations or regions with different operating procedures/requirements (e.g. having the PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** **10. In response to industry comments received, the SDT raised the MVA threshold for "proxy" units from 250 MVA to 350 MVA to ensure that steam units at sites with multiple combined cycle plants are included. The SDT believes that units rated above the 350 MVA thresholds are critical to BES reliability and should have the excitation control system model verified at least once each decade.** **11. The SDT corrected the use of the term "models" in the first bullet of R1.** **12. The SDT revised the measure to address your comment.** **13. The SDT believes that the word "evaluation" could be taken out of context. The SDT did revise Requirement language to address your concern.**
PacifiCorp	Yes	Modeling wind generation without a developed generic model is a concern. If the generic models are not developed once the standard is effective are exceptions going to be made to accommodate this?

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. Generic models are available and there are efforts, as detailed in the Background Information associated with this posting, that are expected to result in more robust models. Requirement R2.1.1 states that the Generator Owner is required to produce documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance. Since the Generator Owner has the final say in determining if the match is adequate or not, to the extent that non-proprietary models can be used to "match" the recorded response from the actual equipment, then that will be sufficient for compliance with the Requirements.		
Georgia Transmission Corporation	Yes	Should references to Planning Coordinator be changed to Transmission Planner (4.2.4 and R5)? Or, should Planning Coordinator be added as a functional entity?Have software manufacturers agreed to provide their models as described in R1?
Response: The SDT thanks you for your comment. The Planning Coordinator is referenced in the standard, but is not responsible for any of the Requirements and therefore is not listed in the Applicability section. **The software manufacturers with dynamic simulation packages used with the Interconnection dynamic stability databases have agreed to provide their models described in R1.**		
Wisconsin Public Service Corp	Yes	We have a number of questions and concerns as follows: o While the Standard uses the word "verified" and "verification" loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? o We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for excitation control was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Response: The SDT thanks you for your comment. In response to your first question the SDT has drafted the standard with minimal technical specificity so that the actual mechanics of verifying the model could be left up to the experts. The SDT drafted a standard that concentrates on stating "what is required" but without stating "how to accomplish what is required". The standard also includes a peer review process. Based on industry		

Organization	Yes or No	Question 4 Comment
comments, the present draft of the standard maintains this same philosophy. **Regarding your second comment, arbitrary large adjustment of model parameters without a valid technical reason is not appropriate. Minor adjustments to model parameters that are within expected tolerances may be appropriate.** **Regarding your third comment, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner.**		
Manitoba Hydro	Yes	1)For Section 4.2 Facilities, the section should refer to 'BES Generating Units and Facilities' instead of restating components of the proposed BES definition.2)Attachment 1 is not clear. Specifically, -the "Condition" in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be 'verified' and serve as evidence for multiple units meeting the conditions listed.-the wording for the allowance of a representative unit to be verified and submitted as evidence for identical units is not clear.-the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected 'with the verified model' which is incorrect.-We suggest the following. A statement that precedes the Attachment 1 table should be added that reads 'For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ' Row 1 should then be Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is â‰¤ 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.
Response: The SDT thanks you for your comment. **(1) The SDT intentionally established the standard applicability as a subset of generators included in the NERC Registry Criteria. The term "BES Generating Units and Facilities" is not specific enough for compliance. There are regional differences that prevent use of this term in defining standard**		

Organization	Yes or No	Question 4 Comment
applicability. **(2) The SDT has significantly revised Attachment 1 to improve clarity.**		
Oncor Electric Delivery Company LLC	Yes	The implementation plan call for a certain % of applicable plants to be in compliance over a certain number of years. Since plants may be registered individually, it is unclear what the term applicable plants is referring to in the implementation phase.Oncor takes the position that the reporting requirements for the Generator Owner as specified in R1, R2,R3,R4,R5 & R6 should be to the Planning Authority and not the Transmission Planner in the ERCOT Region. This would align with the current protocols, operating guide and planning guide that require the ERCOT ISO to be the primary interface with Generation Resources. The ERCOT ISO is registered as the Planning Authority. One option would be a regional variance that would point to the Planning Authority or Planning Coordinator in lieu of the Transmission Planner.
Response: The SDT thanks you for your comment. **The Implementation Plan actually calls for a certain percentage of applicable units on an MVA basis (not plants) to be in compliance over a certain number of years. Specifically for ERCOT, a unit is applicable in the draft standard if: (a) a gross nameplate rating greater than or equal to 50 MVA, connected at the point of interconnection with rating greater than or equal to 100 kV, OR (b) units greater than 20 MVA if it is located at a plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV, OR (c) plants (i.e. all the units in each applicable plant) with a gross aggregate nameplate rating greater than 75 MVA comprised of units that have a gross nameplate rating less than or equal to 20 MVA, connected at the same point of interconnection at greater than 100 kV. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. Since ERCOT is an exception, a regional variance should be considered. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.**		
Exelon	Yes	Requirement R2Exelon is in agreement that the Generator Owner (GO) should provide the generator excitation control system and plant volt/var control model and any necessary input data; however, the Transmission Planner (TP) should be the entity that is responsible for the model verification. Transmission Planning organizations have the expertise to implement and test the models in software, while the GOs have the necessary access to the equipment in the field. Most GOs do not have the software and the necessary personnel with the expertise to perform the modeling and model testing required by this draft Standard. Typically, TPs currently have existing software programs to run the excitation system models. The overall quality of the verification would be best served by having the TP that has knowledge in the model performance verse the GOs that do not have the current expertise in model performance or

Organization	Yes or No	Question 4 Comment
		dynamic system response evaluations.Exelon also believes that the Standard should specifically define the acceptance criteria. If the acceptance criteria are left up to the GOs, then the TOs may have to deal with multiple acceptance criteria within a single Region. At the same time, a single GO may have to work with multiple TOs, which will lead to inconsistency if definition of the acceptance criteria is left up to the TO.Requirement 2.1.1The Standard needs to provide specific guidance as to what criteria a voltage excursion from either a staged test or a measured system disturbance should be in regards to performing the verification. In addition, the SDT should provide specific examples of what types of staged tests would be considered acceptable. It is difficult to comment on the potential impact to the generating units (especially a nuclear generating unit) without knowing the criteria.
Response: The SDT thanks you for your comment. **Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. Also, the Transmission Planner has expertise in overall power system simulation analysis but not necessarily expertise in specific excitation control system modeling. While the Transmission Planner can continue to participate in model verification to whatever extent agreements with the generator entity stipulates, the majority of the SDT and industry, based upon comments received, believes that the Generator Owner should be responsible for this activity. Also, the draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. If the Generator Owner determines that it does not want to develop in-house expertise to perform model verification activities, it can choose to hire consultants or continue any arrangements with its Transmission Planner to completely or partially provide this service as required once every ten years – though the task would be delegated, the Generator Owner would ultimately be responsible for compliance with the applicable Requirements.** **Regarding the second half of the comment beginning with a desire for acceptance criteria, the standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model. It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response. The Generator Owner should not be concerned with "acceptance criteria" proposed by a transmission entity.**		
Dynegy Inc.	Yes	R2.1.1 does not specify the magnitude of the required voltage excursion, i.e. 1%, 2%, etc. Is their a

Organization	Yes or No	Question 4 Comment
		specific required voltage change level?
Response: The SDT thanks you for your comment. No, the standard does not specify a required voltage change level. The SDT drafted a Standard that states "what is required", not "how to accomplish what is required".		
Austin Energy	Yes	ERCOT performs computer modeling based data (RARF) provided by Generators. Please consider allowing an exemption or alternate methods for older unit dynamic data as the information for these older units is not always available. ERCOT has used typical or generic modeling parameters for these units.
Response: The SDT thanks you for your comment. The model can still be verified even if existing dynamic data for older units submitted per the Requirements of MOD-012 and MOD-013 represent typical or generic data.		
Independent Electricity System Operator	Yes	1. We do not agree with some of the requirements.i. R1: Standards should stipulate the "what's" not the "how's". To avoid the perception that the requirement is prescribing the "how", we suggest simplifying the language of Requirement R1 by replacing "Instruction on how to obtain" with "Instructions for obtaining".Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process.ii. R2.1: The phrase "models acceptable to its Transmission Planner" begs the question on what is deemed acceptable and what if the GO disagrees with the TP's determination. To address the two issues, we suggest adding a requirement for the TP to specify the models requirements (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to "in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). 2).iii. We are not sure why Requirement R5 is needed. First of all, it suggests that a Planning Coordinator may request the GO to perform a model review where the request can be technically justified. We wonder if the requirement really means "Transmission Planner" rather than "Planning Coordinator" since TP as the requester and model user is specified throughout the standard. Secondly, if it is indeed TP that was meant to be the requester, then would this request already been covered by Requirement R3? If not, what are the technical justifications? They are not specified in R5, unlike its R3 counterpart. Please clarify and/or revise the requirement as appropriate.iv. 3) R6 stipulates the criteria that may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model. A computer model may fail to initialize due to reasons other than the submitted excitation control system and plant volt/var control function model itself;

Organization	Yes or No	Question 4 Comment
		a no-disturbance simulation may not result in negligible transients due to other reasons; and finally, a disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. System damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three sub-requirements. We suggest this requirement be removed. Further, in many jurisdictions the setting and tuning of excitation control systems and associated power system stabilizers, etc. are determined by the Transmission Planners (or Planning Coordinators); the GOs would simply provide the equipment and set them according to the TP's specification. In this standard, the responsibility is for the GO to verify that the model reflects the actual response of the tested equipment, whose settings have been determined prior by the other responsible entity.2. 4) In the previous posting, we provided 2 comments which in our view, have not been duly and satisfactorily addressed by the SDT and we would like to reiterate them here:i. We suggested that at a minimum, the generator's basic characteristics such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), voltage regulators, turbine-governor systems, etc. as stipulated in MOD-013 that support modeling for dynamic simulations should also be verified. A good excitation system model without a valid generator model will not provide the assurance that the simulation results are valid, which may hurt reliability.In response to this comment, the SDT indicates that: "[it] agrees that appropriate dynamic models are needed for generators, exciters, PSS, and governors. The SDT believes that when testing personnel verify the excitation system model data, they also provide verification of the generator model data. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. The governor model is not verified with the excitation system model since it requires a frequency excursion. Verification of the governor model will be addressed by the MOD-027 standard. Experience indicates verification required by the MOD-026 standard often results in discovery of significant changes to the representation of the generator and exciter, suggesting that model verification provides significant reliability improvement."Generator model parameters need to be verified based on tests conducted during both turbine/governor model verification as well as excitation system model verification. We are however not convinced that those tests that need to be performed during the excitation system model and data verification process, to verify certain portions of the generator model parameters will be conducted as a matter of course. We therefore reiterate our view that the verification of generation model parameters needs to be included within the scope of this standard and we urge the SDT to consider our comments again.ii. 5) We suggested that in some areas on the interconnection, such as those that are sparsely populated,

Organization	Yes or No	Question 4 Comment
		performance of generating units at less than 100 MVA might be critical to reliability. The criteria to allow the TP and PC to identify these units could include: a. A 5% or 10% deviation of any or several of the excitation system's parameters/settings could make an otherwise stable simulation to be unstable; b. Use of generic models for the excitation system or generator would make an otherwise stable simulation to be unstable. c. Other changes or incorrect assumptions for the excitation system or generator would make an otherwise stable simulation to be unstable. The SDT responded that: “After reviewing provided details, the SDT encourages you to review the new process draft (reference Requirement R2) and provide additional comments as appropriate.” Requirement R2 does not contain any provision that a TP (or PC) can request for model verification of units that do not meet the Applicability criteria. Throughout the standards, such a provision does not exist. This could leave room for system to exhibit unstable performance for reasons indicated in our previous comments. We urge the SDT to reconsider our proposal.

Response: The SDT thanks you for your comment.

1) Requirement 1 does describe the “what”. The “what” is that upon request, the Transmission Planner is to provide the Generator Owner data or instructions on how to obtain needed information. As stated in requirement 1, the three bullets identify instructions and data the Generator Owner can request from the Transmission Planner. The Transmission Planner is only required to provide information requested. The SDT believes standard formatting is correct since the Generator Owner determines what, if any of the information identified is requested from the Transmission Planner.

2) Response: Several commenters expressed concern with the new Requirement 5 added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review. Conversely, Requirement 3 only applies to units in the base Applicability (a subset of units identified the NERC Registry Criteria). This requirement is assigned to the Planning Coordinator to address generator owner concern that the transmission planner might request a model review without proper justification. The requirement is written to require a higher level of justification for requesting a model review than simply contacting the generator owner.

3) Response: R6.1, R6.2, and R6.3 represent established industry practice for assuring model usability. The positive damping requirement makes the generator owner provide a response if a new model introduces negative damping. This requirement recognizes that the equipment must be positively damped during actual operation. Negative damping occurring during simulation indicates incorrect modeling. Initialization errors and oscillation transients without disturbance conditions also indicate incorrect modeling.

4) Response: The SDT agrees generator parameters such as the inertia constant, damping coefficient, saturation parameters, direct & quadrature axe reactance’s, and time constants need to be correctly modeled. Since the phrase, “excitation control system” is an IEEE defined term with specific

Organization	Yes or No	Question 4 Comment
meaning; the SDT contends this term incorporates the generation model parameters by definition. The generation model parameters must be correct to successfully verify the excitation control system model. Note that the governor turbine model verification is addressed by the MOD-027 standard. The SDT recognizes the various control systems interact and expects correct modeling data. The purpose of this standard is model verification and not the development of correct modeling parameters. If model verification is not successful, then the modeling parameters are not correct and the generator owner will need to identify and correct bad parameters. This standard intentionally avoids specifying how to correct model parameters with expectation the generator owner demonstrates that model data is correct. **5) The SDT regrets that the provided Reference number in the last Consideration of Comments response was incorrect. The SDT added language to the draft standard in Requirement 5 after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) if technical justification demonstrates the simulated unit response does not match the measured unit response. This will include units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) but are less than the standard's base Applicability (including units > 100MVA for the Eastern Interconnection). In summary, Requirement 5 allows Planning Coordinators to request additional model information, which could include model verification, for units less than 100 MVA that are critical to reliability and have shown that their model does not accurately predict actual equipment response.**		
Wisconsin Electric	Yes	Section A Effective Dates: In 5.2.1, replace "30% of its applicable units" with "20% of its applicable units". There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years.Section B: Requirement R1: Replace "Each TP shall provide the following INSTRUCTIONS AND DATA to its GO..." with "Each TP shall provide the following DATA to its GO...". On the first two bullets, remove the phrase "Instructions on how to obtain..." The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace "Any of the GO's existing ... model data" with "All the GO's existing ... model data...". Since the TP already has this data, it is more straightforward to simply provide all relevant data to the GO. Requirement R2: Replace the first sentence with, "Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models..." The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3.In R2.1.1, replace "Documentation demonstrating the ... model response matches the recorded response" with "Documentation WHICH MAY BE USED TO DEMONSTRATE that the ... model response matches the recorded response". In R2.1.3, 2.1.4, and 2.1.6 replace "model structure" with "block diagram". In Requirement R3, replace "90 calendar days" with "180 calendar days", to allow more time to work through the technical challenges relating to these models.In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace "walk down" with "inspection". Comments on Attachment 1:1. Remove the note which says, "Note that local grid codes may specify...".2. Under "Conditions" for existing generators, it is not clear why there are references to both a ten year period and an eleven year period. Also, replace "Subjected to an activity resulting in an alteration of the response of the excitation control system" with "Changes to control system or parameter values".3. Under the

Organization	Yes or No	Question 4 Comment
		exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under "Periodicity" for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis.Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.

Response: The SDT thanks you for your comment.

1. **The SDT considered industry concerns provided in response to the first posting of the standard for this issue and decided to revise the timeframe following standard approval for the first set of models required to be verified from "after 2 years of regulatory approval, 10% of its applicable units per Interconnection on a MVA basis" to "…four years following applicable regulatory approval….Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R1." In addition to allowing entities additional start up time to develop this expertise, the revised timeline enables traditional staged testing to be performed concurrent with a scheduled planned maintenance outage. The SDT believes this change allows adequate time for entities to perform model verification activities.**
2. **The SDT believes it is necessary to provide instructions for obtaining the data since a) the SDT anticipates most entities will post the "acceptable list of models" on a website, and b) providing instructions on how to obtain block diagrams or data sheets will help ensure vendor dynamic simulation software data sheets are legally obtained.**
3. **It is acceptable for a Generator Owner to request information for any of its units or plant excitation control systems.**
4. **Requirements R6.1 through R6.3 specifies how a Transmission Planner determines if the model is usable. This determination should not be confused with verifying the model response matches actual equipment response. A model is not considered "usable" if angle drift occurs without a disturbance condition present or if poorly damped oscillations occur when disturbance conditions exist. As required by R2, model verification is ensuring that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event).**
5. **The phrase "may be used" would undermine the primary reliability related intent of the standard which is to ensure that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event). Also, the SDT intends to keep the phrase "model structure" since a model structure is a block diagram without parameter values.**
6. **Requirement R3 does not require the Generator Owner to verify the model. Allowing more than 90 days only prolongs the dialog.**

Organization	Yes or No	Question 4 Comment
7. Requirement R5 does not require the Generator Owner to verify the model. Allowing more than 90 days prolongs the process of updating the model which the Planning Coordinator needs to have revised so that accurate BES stability limits can be calculated. The SDT regrets that it could not find the reference to "walk down". **8. Regarding the first two Attachment 1 comments, the Attachment has been revised.** **9. Regarding your Attachment 1 comment pertaining to allowable MVA size, the SDT responded to industry comments by raising the MVA threshold for "proxy" units from 250 MVA to 350 MVA to ensure that steam units at sites with multiple combined cycle plants are included. The SDT believes that units rated above the 350 MVA threshold is critical to BES reliability and should have the excitation control system model verified at least once each decade.** **10. Regarding your second to last Attachment 1 comment, the SDT believes that if any control changes are implemented, they would be performed at the same time a staged testing is conducted (for example, adjusting gain based on the results of a step change voltage test).** **11. Regarding your final Attachment 1 comment, the SDT expects either traditional staged testing or ambient monitoring will be used to collect data for model validation. As such, there is not a need to provide additional incentive to the TO/TOP.**		
We Energies	Yes	Section A Effective Dates: In 5.2.1, replace "30% of its applicable units" with "20% of its applicable units". There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years. Section B: Requirement R1: Replace "Each TP shall provide the following INSTRUCTIONS AND DATA to its GO..." with "Each TP shall provide the following DATA to its GO...". On the first two bullets, remove the phrase "Instructions on how to obtain..." The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace "Any of the GO's existing ... model data" with "All the GO's existing ... model data...". Since the TP already has this data, it is more straightforward to simply provide all relevant data to the GO. Requirement R2: Replace the first sentence with, "Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models..." The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3. In R2.1.1, replace "Documentation demonstrating the ... model response matches the recorded response" with "Documentation WHICH MAY BE USED TO DEMONSTRATE that the ... model response matches the recorded response". In R2.1.3, 2.1.4, and 2.1.6 replace "model structure" with "block diagram". In Requirement R3, replace "90 calendar days" with "180 calendar days", to allow more time to work through the technical challenges relating to these models. In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace "walk down" with "inspection". Comments on Attachment 1: 1. Remove the note which says, "Note that local grid codes may specify...". 2. Under "Conditions" for existing generators, it is not clear why there are

Organization	Yes or No	Question 4 Comment
		references to both a ten year period and an eleven year period. Also, replace “Subjected to an activity resulting in an alteration of the response of the excitation control system” with “Changes to control system or parameter values”. 3. Under the exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under “Periodicity” for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis. Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.

Response: The SDT thanks you for your comment.

1. **The SDT considered industry concerns provided in response to the first posting of the standard for this issue and decided to revise the timeframe following standard approval for the first set of models required to be verified from “after 2 years of regulatory approval, 10% of its applicable units per Interconnection on a MVA basis” to “…four years following applicable regulatory approval….Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R1.” In addition to allowing entities additional start up time to develop this expertise, the revised timeline enables traditional staged testing to be performed concurrent with a scheduled planned maintenance outage. The SDT believes this change allows adequate time for entities to perform model verification activities.**
2. **The SDT believes it is necessary to provide instructions for obtaining the data since a) the SDT anticipates most entities will post the “acceptable list of models” on a website, and b) providing instructions on how to obtain block diagrams or data sheets will help ensure vendor dynamic simulation software data sheets are legally obtained.**
3. **It is acceptable for a Generator Owner to request information for any of its units or plant excitation control systems.**
4. **Requirements R6.1 through R6.3 specifies how a Transmission Planner determines if the model is usable. This determination should not be confused with verifying the model response matches actual equipment response. A model is not considered “usable” if angle drift occurs without a disturbance condition present or if poorly damped oscillations occur when disturbance conditions exist. As required by R2, model verification is ensuring that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event).**
5. **The phrase “may be used” would undermine the primary reliability related intent of the standard which is to ensure that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event). Also, the SDT intends to keep the phrase “model structure” since a model structure is a block diagram without parameter**

Organization	Yes or No	Question 4 Comment
values. **6. Requirement R3 does not require the Generator Owner to verify the model. Allowing more than 90 days only prolongs the dialog.** **7. Requirement R5 does not require the Generator Owner to verify the model. Allowing more than 90 days prolongs the process of updating the model which the Planning Coordinator needs to have revised so that accurate BES stability limits can be calculated. The SDT regrets that it could not find the reference to "walk down".** **8. Regarding the first two Attachment 1 comments, the Attachment has been revised.** **9. Regarding your Attachment 1 comment pertaining to allowable MVA size, the SDT responded to industry comments by raising the MVA threshold for "proxy" units from 250 MVA to 350 MVA to ensure that steam units at sites with multiple combined cycle plants are included. The SDT believes that units rated above the 350 MVA threshold is critical to BES reliability and should have the excitation control system model verified at least once each decade.** **10. Regarding your second to last Attachment 1 comment, the SDT believes that if any control changes are implemented, they would be performed at the same time a staged testing is conducted (for example, adjusting gain based on the results of a step change voltage test).** **11. Regarding your final Attachment 1 comment, the SDT expects either traditional staged testing or ambient monitoring will be used to collect data for model validation. As such, there is not need to provide additional incentive to the TO/TOP.**		
Great River Energy	Yes	We appreciate the drafting team's consideration in Section A.6 to allow a unit that has already verified its excitation system to be considered compliant. However, it is not clear how this section helps. How does the Generator Operator demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff besufficient? Will the regional entities be willing to validate that they have confirmed regional criteria?This standard is overly administrative by memorializing the interactions between the Generator Operator, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck. They are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are needed to accomplish the purpose of this standard. They are: ne requirement for theGenerator Operator to perform the test and one for the Transmission Planner to verify the model is accurate.Requirement R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6. This just represents one of the issues with

Organization	Yes or No	Question 4 Comment
		memorializing the interactions between the Transmission Planner, Planning Coordinator and Generator Operator in the standards.Because the tests to verify the excitation model can be expensive, there should be a demonstrated need to perform a test. Summaries of field test results posted with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit. That does not even include opportunity costs from lost energy sales should the test cause the unit to trip. Thus, if there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the generator operator should be able to wait for a system disturbance appropriate enough to verify its model.Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Operator should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.

Response: The SDT thanks you for your comment.

1. **It is beyond the scope of the SDT to specify how an entity will provide evidence if requested to verify a model compliant with the applicable regional entity polices, guidelines, or criteria. It is hoped that documentation and/or correspondence created during the model verification process was compliant with regional entity policies, guidelines, or criteria and maintained by the Generator Owner for use as evidence. The decision to attest or validate regional criteria will have to be determined by the respective region.**
2. **Regarding your comment suggesting that R1 should be struck, the SDT cannot draft a Requirement for a Functional Model Entity without assurance that they have the proper information to satisfy the Requirement. R1 is necessary to ensure the Generator Owner has the proper information to comply with R2.**
3. **Regarding your comment suggesting that R3, R4, and R5 should be struck, the SDT acknowledges that these Requirements are "exception type" Requirements that should rarely be used however the SDT believes striking them from the standard would be detrimental to reliability. Without these Requirements, model accuracy issues may not be resolved for ten years.**
4. **Regarding the comment addressing Requirement 6 language, the Requirement references usability testing only which can be readily completed by the Transmission Planner. R6 language does not prevent the Transmission Planner from requesting the Generator Owner to verify information if there is evidence that the model is incorrect. The third bullet of R3 mandates that the Generator Owner must respond to evidence from the Transmission Planner that the modeled response does not match the recorded response and this language allows the Transmission Planner, assuming supporting evidence is available, to request a review at any time..**
5. **Regarding your comment about the need for model verification, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Phase III-IV NERC Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will**

Organization	Yes or No	Question 4 Comment
improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner. **6. Regarding your last comment, please note that the Requirements R3 and R5 only require the Generator Owner to respond to the Transmission Planner within 90 days, and that response could be a plan to verify the model. Once this response is provided, the Generator Owner has one year to collect a voltage excursion and another 180 days to complete model verification based on the current language of Attachment 1.**		
Duke Energy	Yes	1) If System Models are poor today, it is probably due to a lack of understanding on what models are required, setpoint control and what changes need to be communicated to Transmission when plant projects are done. Periodic reverifications are probably not the right way to ensure reliability. Instead there should be an event-based revalidation requirement, such as if you replace the control system or recalibrate the control settings on an existing unit, replace the rotating exciter or rewind a generator. An approach where there is an initial validation effort to get today's models consistent with installed equipment is clearly needed. However, assurance that future models will remain valid requires that there is a program in plant project processes to revalidate when appropriate, and thus a requirement to show that the company has the needed project processes and has followed that process is the right way to approach this.2) There needs to be a requirement for the entity responsible for actually inputting the models and data to do so on a timely basis. This should be an annual update of data to be submitted to the interconnected models. As currently written, there is a requirement for the GO/GOP to submit information, but they do not input directly into the interconnected system models. MOD-010, MOD-011, MOD-012 and Mod-013 don't currently ensure that data is incorporated in a timely fashion.3) Since GO/GOPs do not always have electrical system modeling expertise, nor participate in interconnected system models groups such as the MMWG which sometimes changes how equipment is modeled, there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF are considering a collaboration to do so.4) Identically designed generation units are identical in control response, independent of site location. New techniques for validation eliminate the impact of the grid on the validation efforts. Thus, credit for sister unit validations should be available independent of the location of a unit.5) Discussions during the EPRI PPPD users group indicate certain parameters in the models are temperature sensitive, and thus verification and adjustment of models should be done under conditions that reflect normal operating conditions. An on-line voltage step test or DFR data from an event is the best way to perform the validations. It's not clear if validations against off line tests would actually make the models worse, but the industry should be encouraged to do validations on line near full power.6) R2, 2.1.3 Total unit inertia should be given to include all coupled rotating elements. The way this is currently worded, it could lead generators to only provide the generator H values.7) Footnote 4 - Delete the phrase "or evidence that the simulated unit or plant response does not match measured unit or plant response". Otherwise this standard could be made applicable to a small unit that has no impact on reliability.

Organization	Yes or No	Question 4 Comment

Response: The SDT thanks you for your comment.

1. **The philosophy adopted for the draft standard is based on recently completed NERC sponsored Field Testing. Field Test results confirm excitation system model verification results in higher quality dynamic data. Since excitation system verification is costly and requires significant manpower, the SDT believes the applicability should be a subset of the NERC Registry Criteria and a ten year verification periodicity is appropriate for reliability. Also, the standard includes "event-based" validation requirements to ensure that the model is verified when issues are discovered (Requirement 3, third bullet).**
2. **The results of model verification are required to be transmitted to the Transmission Planner per Requirement 2 and Attachment 1. Sufficient time is provided for the Generator Owner to verify the equipment response matches the predicted response. While the SAR for MOD-026 addresses model verification, which the SDT believes includes the transmittal requirements specified in Attachment 1; it does not address the data submission requirements of MOD-010 and MOD–012.**
3. **Regarding the third comment, the SDT agrees development of model verification guides by credible industry groups such as the NATF and EPRI is a worthy endeavor.**
4. **Regarding the fourth comment, the SDT respectfully asserts that the "same physical location" requirement is necessary since this language provides a strong indication of equipment and settings similarity (which can be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in different geographic locations or regions with different operating procedures/requirements (e.g. having the PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.**
5. **Regarding the fifth comment, the SDT maintains that the standard should state "what is required" and not specify "how to perform what is required". The SDT refrains from entering the debate because both the online and offline step change voltage tests and the ambient event test are adequate for performing model verification.**
6. **Regarding the sixth comment, the SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.**
7. **Regarding the last comment, several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review.**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Western Electricity Coordinating Council</td><td>Yes</td><td>Requirement R1, first bullet. Grammatically, should the word model in the first bullet be models?Requirement R4 requires the Generator Owner to provide revised model data or plans to perform model verification. The way I interprete the wording of Requirement 4 is that the model data or plans to perform model verification are due within 180 calendar days. If the GO provides plans to perform model verification and submits the information on their plans within 180 days, is there any time limit as to when the model verification must be performed? If so I suggest it should be included in the language of the Requirement. If the actual verificatio must be done within 180 days this should be clarified becasue right now it just looks like only the plans have to be submitted within 180 days.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment.
1. Regarding the first comment, the SDT has corrected the error in R1.
2. Regarding the second comment, the Generator Owner has 180 days to respond, and that response could be a plan to perform model verification. If the Generator Owner plans to perform model verification, then footnote 5 specifies that the ten year periodicity would be reset as detailed in Attachment 1. More specifically, once the Generator Owner states an intention to re-verify the model, Attachment 1 allows up to 365 days to record and collect an ESC response and then is allowed up to 180 days to transmit the verified model and documentation to the Transmission Planner.</td></tr>
<tr><td>ISO New England Inc.</td><td>Yes</td><td>1) This standard may lead Generator Owners to violate another NERC Standard; this standard implies in requirement R4 along with footnote 6 that Generator Owners could have 180 days to notify its Transmission Planner that an AVR status has changed. The VAR standards require notification within 30 minutes of a change in AVR status.Requirement R4 is also a direct violation of the ISO/FERC Tariff Section I.3.9 that requires generators to provide information prior to making material changes to equipment characteristics. Allowing generators to make changes such as these without prior review represents a significant reliability concern.

2) MOD 26 needs to clearly state that non-proprietary models need to be provided by Generator Owners, otherwise a major reason (NERC MMG) for model collection will be undermined.As written, the intent of requirement R2.1.1 is unclear.

3) How are stabilizers and excitation limiters to be addressed? How large does the voltage excursion need to be? This requirement needs to be made much more specific.

4) With respect to requirement R1, the standard should allow user models to be provided. The second bullet point implies that models would only be allowed from a list of standard models. User written models</td></tr>
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Organization	Yes or No	Question 4 Comment
		may provide more accurate representations of actual equipment installations. However, these models cannot be proprietary and must be able to be distributed.In requirement R5.2 bullet 1 - generator owners should not be providing generic model data. In requirement R5.2 bullet 2 - what constitutes a “walk down” of the equipment? 5) Suggest replacing with “Updating parameters based on actual field verification of equipment settings.”This standard should indicate what constitutes the excitation system and should indicate that it includes a power system stabilizer and limiters. 6) This standard addresses existing generators, but should also address new generators.In regard to the Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas with very little verification for up to ten years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within it’s area.

Response: The SDT thanks you for your comment.

1) The requirements of MOD-026 do not usurp the requirements of other standards. Providing notification of AVR status change is not the same as verifying model data following equipment status change that may affect the model. MOD-026 requires model verification and this cannot be performed until after equipment changes occur and the generator is operating. Also, MOD-026 addresses verification of ECS models that are in service. MOD-026 does not alter requirements for preliminary model data as specified by any Tariffs.

2) Requiring Generator Owners provide models based on an acceptable model list provided by the Transmission Planner is intended to establish usable models. Part of this intention is to address the necessity for non-proprietary models.

3) Generator owners are expected to provide correct stabilizer and excitation limiter data. MOD-026 requires verification of the complete model but does not verify every detail of the model. Limits are difficult to verify using staged or ambient tests. The generator owner and subject matter experts have to determine how to develop correct data.

4) The standard does not prevent user models however the model must be on the list approved by the Transmission Planner. An equipment “walk down” to correct model parameters could be as simple as identifying by observation in the field that equipment gain or limit setting values are incorrectly represented in the model.

5) The standard uses the IEEE term “excitation control system” which includes the PSS, limiters, and generator. The standard requires verification that model data matches equipment performance for the complete voltage control system.

6) The SDT addressed new equipment in Attachment 1 and provided 180 days to complete model verification. Generator owners are required by other standards to provide correct model data so the SDT believes the implementation time frame allows sufficient time to adequately verify the model without impacting Generator Owner ability to develop capabilities and verify models for their other units.

Organization	Yes or No	Question 4 Comment
Ingleside Cogeneration LP	Yes	MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities.If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES voltage response - and have already the recording equipment needed to validate performance.
Response: The SDT thanks you for your comment. The SDT believes that the Generator Owner is in the best position to determine realistic and reasonable model representation of installed equipment. For this reason, the standard gives the Generator Owner authority to determine if the model adequately represents performance of installed equipment. It is not desirable to link this standard with the DME standard under development. Also, the DME standard applies to fault recorders and PMU equipment. Low resolution data is adequate for verification. The SDT agrees that if DME is already in place, especially if it is monitoring the appropriate quantities required for excitation control system verification, then it should be simpler to capture the required data for verification. The applicability section requires verification of units larger than the MVA threshold gross nameplate rating specified for each interconnection and this threshold is intended to emphasize the importance of modeling critical units.		
Southern California Edison Company	Yes	SCE believes that the Section 4.2.4 of the Applicability Section should be revised to read "Any technically justified unit requested by the Transmission Planner." We believe that the Transmission Planner is the appropriate functional entity for this role.In addition, SCE believes that Requirement 1 should be revised to allow the Transmission Planner a full 60 days in which to provide the information to the Generator Owner. At various times, Transmission Planners may be inundated with such requests from Generator Owners and may require the extra time in which to respond.
Response: The SDT thanks you for your comment. In response to your first comment, the second posting of the standard has proposed a process where the Planning Coordinator can request a review of an excitation control system model for a unit not specified in the standard Applicability section. This requirement was added by the SDT in response to industry asking if a transmission entity should be allowed to identify additional units beyond those identified in the base Applicability. The base Applicability, though expanded in this posting, continues to be a subset of units identified by the NERC Compliance Registry. Also, the time period in Requirement 1 has been increased to 90 days to match the time period in the VSL.		
Ameren	Yes	Our comments/concerns are : 1)The wording for Requirement 2.1.4 should be changed to read “Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator”. Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment.2)In Requirement R5, the term “technically justified request” needs to be clarified. 3)In Requirement R2.1.3, it should be clarified that “rotational inertia” should include

Organization	Yes or No	Question 4 Comment
		all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself.4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included.5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators.6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy.7)The draft uses the term "Point of Interconnection" in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition.8)Footnote 6 should be a set of sub-requirements for R4.9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard.10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote - it's too important in determining which generators must comply.
Response: The SDT thanks you for your comment. 1) The SDT has revised R2.1.4 incorporating the essence of your suggestion. **2) The SDT has revised Requirement R5 using a footnote to define the phrase, "technically justified" as the simulated unit or plant response does not match measured unit or plant response.** **3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.** **(4) The SDT is only proposing verification of units rated 20 MVA at plants which exceed the interconnection established MVA threshold (which is 100 MVA for the Eastern Interconnection). Even with the MVA threshold satisfied, units satisfying sister/proxy unit criteria will not have to be verified, further reducing the number of units actually tested.** **(5) The SDT believes sister/proxy unit criteria established is adequate.** **(6) MOD-012 and MOD-013 requires submission of the latest equipment dynamic model data. MOD-026 requires verification of the equipment dynamic model data.** **(7) Your observation regarding the phrase "point of interconnection" is correct. Please note that this phrase is not capitalized in the standard.** **(8) The SDT believes providing the list associated with Footnote 6 in the Requirement section would make the standard cumbersome to read.** **(9) The SDT believes that Section 6, since it addresses early compliance considerations, is important to require its own "section" in the standard.** **(10) The SDT believes providing the list associated with Footnote 2 in the main body of the standard would make the standard cumbersome to read.**		
American Electric Power	Yes	Standard models may not be available for wind units and wind facilities (which appear to be within scope), particularly aggregate reactive and frequency response controls at the farm level. As a result, it might be difficult to obtain and provide such information.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. Generic models are available and there are efforts, as detailed in the Background Information associated with this posting, that are expected to result in more robust models. Requirement R2.1.1 states that the Generator Owner is required to produce documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance. Since the Generator Owner has the final say in determining if the match is adequate or not, to the extent that non-proprietary models can be used to "match" the recorded response from the actual equipment, then that will be sufficient for compliance with the Requirements.		
Texas Reliability Entity	Yes	(1) The implementation period in this standard is far too long. It is unreasonable to allow 11 years for a GO to provide a verified model for 50% of its generation capacity. All generation should comply with Requirement 2 within 3-5 years.(2) The periods allowed for providing correction of identified model deficiencies and updates for system changes are too long. It appears (from Attachment 1) that a GO has almost 2 years to provide a corrected verified model after a request from a TP or an equipment change (per Requirements R3, R4 and R5). This work should be completed within one year to ensure accurate system modeling.(3) It is unclear exactly what is required by Attachment 1, and how the material in the attachment relates to the Requirements. The Attachment appears to contain additional requirements. We suggest moving the required actions described in Attachment 1 into the applicable Requirements, such as the requirements and time periods for recording responses and providing new information to the TP. (4) It is unclear what the 10 and 11 year periods/cycles referenced in the first two rows of Attachment 1 refer to. This needs to be clearly explained somewhere.(5) It is our understanding that this standard is intended to require re-verification of models at least every 10 years, but there is no requirement that clearly sets forth any re-verification requirement or period. (6) Requirement 6 requires the TP to determine if a model is "usable" based only on whether the model is functional, omitting any consideration of whether the model is reasonably accurate. An incorrect model could satisfy 6.1, 6.2 and 6.3. We suggest adding an R6.4 relating to whether the model is reasonably accurate, i.e., whether it reflects actual unit performance.(7) In 4.2.3, in the first bullet, "with rating greater than" should be changed to "at greater than," which is clearer and consistent with the parallel descriptions in neighboring sections.(8) In the "Consideration for Early Compliance" section, first bullet, "applicable regional entity policies" should be changed to "applicable region policies." In our region, and perhaps others, there are applicable policies, but they are not "regional entity policies."(9) Several very informal terms are used that should be replaced with more specific language, such as "walk down" (R5.2) and "local grid codes" (Attachment 1). In R6.2, the term "negligible transients" in too indefinite and should be replaced by a more objective measure. (10) The terms "unit," "plant," and "facility" are used inconsistently in the draft.(11) M4 refers to a "request" and a "response," but there is no request/response interchange in the associated Requirement R4.
Response: The SDT thanks you for your comment. **Regarding the first comment, in the current draft of the standard, all of the units that meet the Applicability section are required to have their models**		

Organization	Yes or No	Question 4 Comment
verified within 11 years – 50% will be verified within seven years (six years to capture a voltage excursion, and then one year to finish the model verification). Also, the SDT believes, and the majority of industry responders when asked the question in the first posting agree, that the implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a 5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications. **Regarding the second comment, from the time it is decided that model verification is necessary, one year is allowed to capture the recording of the equipment response to an appropriate voltage excursion. One year is not an unreasonable amount of time to perform a staged test or to capture an ambient event. After the event is captured, only 180 days is provided for the completion of model verification.** **Regarding the third comment, the SDT believes that the periodicity of capturing events and subsequently finishing the verification including the documentation is not an activity directly related to the reliability of the BES. The Attachment has been re-worked for clarity in the current draft.** **Regarding the fourth and fifth comment, Attachment 1 has been re-worked for clarity in the current draft.** **Regarding the sixth comment, both the second and third bullets in Requirement 3 allow the Transmission Planner a process to address inaccurate models with the Generator Owner.** **Regarding the seventh comment, the SDT thanks you for catching this oversight and has made the correction.** **Regarding the eight comment, the SDT agrees.** **Regarding the ninth comment, the SDT removed the term “local grid codes”. Regarding the other terms, the SDT feels that they are terms that are well understood by industry.** **Regarding the tenth comment, the SDT used the term “unit” for a single generating unit, the term “plant” for sites with multiple units, and “facility” when appropriate for either a single unit or a plant.** **Regarding the eleventh comment, the SDT thanks you for your observation and has modified M4 appropriately.**		
RFC	Yes	RFC offers the following suggestions regarding the Violation Severity Levels:1. VSL for R1 - There is a disconnect between the date listed in the VSLs and requirement. The timeframe for the “Lower” VSL starts at 90 calendar days though the requirement states “within 30 calendar days”. Where does an entity fall if they provide instructions 45 calendar days of receiving the request? Based on the current VSLs, they would not even fall under the “Lower” VSL.2. VSL for R3 - To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “...as specified in Requirement R3.” Or conversely remove this language from the “Severe” VSL and replace with “R3”.3. VSL for R4 - To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “...as specified in Requirement R4.” Or conversely

Organization	Yes or No	Question 4 Comment
		remove this language from the "Severe" VSL and replace with "R4".4. VSL for R5 - To be consistent with the language in the "Severe" VSL, add the following words to the end of the "Lower", "Moderate" and "High" VSLs: "...as specified in Requirement R5." Or conversely remove this language from the "Severe" VSL and replace with "R5".5. VSLs for R6 - To be consistent with the language in the "Severe" VSL, add the following words to the end of the "Lower", "Moderate" and "High" VSLs: "...as specified in Requirement R6." Or conversely remove this language from the "Severe" VSL and replace with "R6".
Response: The SDT thanks you for your comment. Regarding your first comment, Requirement 1 has been corrected to specify 90 days instead of 30 days. This resolves the discrepancy between the Requirement and the Lower VSL. **Regarding your remaining comments, the language in the Severe VSL for R3, R4, R5, and R6 was revised to match the format of the other VSLs.**		
Consolidated Edison Co. of NY, Inc.	Yes	Requirement R5 - Please define the term "technically justified." We recommend using wording similar to Comment form paragraph 8) in that definition:"[S]upply technical justification that demonstrates either a) the unit affects a stability limit, or b) the simulated unit response does not match a measured unit response (most likely captured during a system disturbance event)."
Response: The SDT thanks you for your comment. Regarding the last comment, several comments expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review.		
PPL Electric Utilities	Yes	1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word "software;" and para. R2.1.1 should state that "Verification consists of developing one or more models that collectively include the following information:"The present R2.1.1 text, "acceptable to the Transmission Planner," is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO's first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the

Organization	Yes or No	Question 4 Comment
		Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified status only after being accepted by the Transmission Planner, the term "verified model(s)" in the R2 Violation Severity Levels should be replaced with, "initial submittal of proposed-verified model(s)". 3. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in para. R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026.4. The definition of a "technically justified request" in para. R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.

Response: The SDT thanks you for your comment. (1) The SDT believes it is better for industry to have 180 days to perform model verification activities in lieu of establishing a universal 60 day period to perform all activities required just to achieve timeframe consistency among the Requirements.

(2) The SDT believes language is clear following removal of the word "collectively" from the paragraph. The SDT also points out that standard language proposed is for facilitating verification of the dynamic model, and not development of the dynamic model.

(3) The standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model. It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response. The Generator Owner should not be concerned with "acceptance criteria" proposed by a transmission entity.

(4) The "technical justification" is not related to Requirements R6.1 – R6.3. These requirements only address if the model is useable by integrating successfully into the Transmission Planner's dynamic simulation software. Several comments expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated

Organization	Yes or No	Question 4 Comment
unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review. **(6) The “walk down” to correct model parameters could be as simple as identifying in the field that equipment gain or limit setting values are incorrectly represented in the model.**		
American Transmission Company	Yes	Please give consideration to the following suggestions:1. In Applicability, 4.2, Include the explanation that “average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value” since some have asked how this value is defined and calculated.2. In Applicability, 4.2.4 - add “Transmission Planner” to this item because Transmission Planners may also have insight and the means to provide technical justification for the inclusion of specific units in their system.3. In Requirements, R1, bullet 1 - remove this bullet 1, or combine it with bullet 2, because it appears to be redundant with bullet 2, rather than distinctly different.4. In Requirements, R2.1.4 - replace “model structure and data” with “block diagram and model parameters” for more clarity.5. In Requirements, R2.1.6 - replace “model structure and data” with “manufacturer, model number, block diagram, and model parameters” for more clarity and specificity.6. In Requirements, R2.1.6 - add “and indicate whether the power system stabilizer is planned to be in-service and out-of-service in the planning horizon.”7. In Requirements, R4 - revise the text from “within 180 days of making changes” to “within 180 prior to making changes” for more clarity.
Response: The SDT thanks you for your comment. The responses below are numbered to match the comments. **1. To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).** **2. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.**		

Organization	Yes or No	Question 4 Comment
3. Regarding bullets 1 and 2 in Requirement R1, the information described in each bullet is distinctly different. The first bullet “Instructions on how to obtain the list of acceptable excitation control system and plant volt/var control function model for use in dynamic simulation” is literally just a list of acceptable model types. For many entities, especially those which utilize dynamic simulation software that is widely utilized, this is all the information that they will require. The second bullet, " Instructions on how to obtain the Transmission Planner’s software manufacturer’s dynamic excitation control system and plant volt/var control function system model library block diagrams and/or data sheets”, pertains to the actual block diagrams and/or data sheets (as opposed to only a “list” of model types in bullet 1). The information in the second bullet will likely be required by entities that do not use dynamic simulation software that is widely utilized. **4. The SDT intends to keep the phrase “Model Structure” since a model structure is a block diagram without parameter values.** **5. The language of R2.1.4 has been revised to align with the style of R2.1.6.** **6. Regarding R2.1.6, the SDT does not believe it is appropriate to communicate PSS status as part of a modeling standard.** **7. The SDT believes that the intent of Requirement R4 is captured with the current language. The standard does not address notification regarding equipment changes, nor does it address the transmittal of preliminary model data from the equipment manufacturer; it addresses a requirement for the verification of the model for the “changed out” equipment. The models for the new equipment cannot be verified until the equipment is installed and available.**		
Indiana Municipal Power Agency	Yes	IMPA appreciates the efforts of the SDT on getting the applicability section correct for the plants or units that truly impact the stability response of the BES. However, the standard does contain a loop-hole to the SDT's intent. On page 3 of 16, footnote 4 to the applicabilty section (4.2.4)states: "a technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response". The first or word in that sentence should be replace with the word "and". A technical justification for verifying each of those units and plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit should both be required. By requiring both of these items, it might prevent units the size of 1MW from having to perform this standard.In addition, who qualifies what is a technically justified unit or what is a technical justification? Past history as shown that technicaly justifications have been used "losely" by different regions and entities. The Generator Owner should have some means of appealing this request by the Planning Coordinator.
Response: The SDT thanks you for your comment. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning		

Organization	Yes or No	Question 4 Comment
Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.		

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Generator Verification – PRC-024-1 — Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the Second Posting of PRC-024-1 Generator Performance During Voltage and Frequency Excursions. These standards were posted for a 45-day public comment period from June 15, 2011 through August 1, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. Also included in this report are comments received from the initial ballots and non-binding polls conducted during the last ten days of the 45-day comment period. There were 66 sets of comments, including comments from approximately 185 different people from approximately 120 companies representing all 10 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT proposed two new definitions for Voltage Excursion and Frequency Excursion. A slight majority agreed with the proposed definitions. The majority of "No" votes disagreed with the voltage excursion portion of the question while there was only one vote disagreeing with the frequency excursion portion. After reviewing all comments the SDT made the following changes:

1. The two new terms proposed in the standard were removed. The voltage and frequency excursion values are now located in the requirements where they apply.

2. Attachment 1 (Off Nominal Frequency Capability Curve) was revised to clarify the "no trip" zone.

3. Attachment 2 (Voltage Ride-Through Time Duration Curves) has been clarified. The per unit voltage base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES). In addition, the

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

definition was modified to include the phrase, "voltages in the curve assume minimum phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum phase-to-ground or phase-to-phase voltage for the high voltage duration curve."

The GVSDT proposed Requirements R1 and R2 to detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Stakeholders were asked if they believed that the draft of these two requirements, including footnote 1, clarified that a Generator Owner is not required to have protective relaying installed or set for these functions. Stakeholders generally agreed that footnote 1 does clearly state that a Generator Owner is not required to have protective relaying installed or set for frequency or voltage protection. Many of the stakeholders made additional comments beyond the scope of the question regarding the intention of Requirements R1, R2, and R3 and provided clarifying language examples. In response, the SDT made the following changes:

1. The Requirement Parts were revised in Requirement R1. Part 1.5 was moved into the body of R1. The requirement now reads:

   "R1. Each Generator Owner that has generator frequency protective relaying[2] activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not trip within the "no trip zone" of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

   1.1. A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec.

   1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

2. Requirement Part 2.1.1 was removed from Requirement R2. The body of the requirement and the remaining Parts were modified to clarify intent. The requirement now reads:

   "R2. Each Generator Owner that has generator voltage protective relaying1 activated to trip its new or existing generating unit or generating plant shall set its protective relaying such that it does not trip as a result of a voltage excursion (at the point of interconnection) that remains within the "no trip zone" of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and

[2] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit2 or generating plant.: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1. When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. If a Transmission Planner's study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner's voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.

2.1.2. Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2.

2.1.3. If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

3. Requirement R3 was changed to clarify the intent of non-protection system limitations and when such limitations must be addressed. The requirement now reads:

"3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.

- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard)."

During the Quality Review process prior to the previous posting, a new requirement R4 was added based on the comments of the reviewers. This resulted in requirement numbers being incorrect for Questions 3 and 4. ***The GVSDT will ask these two questions again on the upcoming comment form for the successive ballot.*** A summary of the comments received is in the following paragraphs.

Relating to question 3: The GVSDT added Requirement R5 to allow owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information was intended to provide Transmission Planners with information useful in performing planning studies. In the comment form, the question erroneously asked about R4 rather than R5. A few commenters made comments regarding R4 while the vast majority commented related to R5.

Several commenters felt that there is no additional reliability gain in Requirement R5. Their comments indicated that the information is not useful and that there is little technical value in this information. A few commenters expressed the opinion that it is very difficult, if not impossible, to predict the consistent response of the balance of (a generating) plant to the system excursions shown in Attachment 1 & 2. Further, several commenters expressed the opinion that it is unlikely that any steam plant will survive for the entire “no trip zones” of the attachments. Other, less frequent, comments included the following:

- R1-R4 adequately fulfill the purpose of the standard.
- Standard requirements should be limited to devices that directly respond to the generator V and F – write standard to exclude all aux system equipment.
- The TP needs only to know when the protective relaying V-t and F-t will trip the unit so the models can switch the generators off when the simulated V and F levels are reached.
- 30 days is too short for a response.

Based on comments received, the GVSDT revised R5 (which is now R4) to:

“R4. Each Generator Owner of an existing generating unit or generating plant shall provide an estimate of that unit’s performance during Frequency/Voltage Excursions to each requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit or generating plant) within 60 calendar days of receipt of a written request, to ensure the accuracy of planning studies and system modeling studies. The estimate shall include: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

4.1. An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection described by dynamic simulation provided by the Transmission Planner. If the Generator Owner expects the existing unit, generating plant will remain connected for longer than 10 minutes, the estimate should indicate the existing unit or generating plant is not expected to trip.

4.2. Identification of the bases for the estimates developed for 4.1 which may include, but is not limited to: experience, actual event histories, or sound engineering judgment.”

Relating to Question 4: The question mistakenly referred to Requirement R5 due to changes to the standard made in response to the Quality Review. This error was observed by the stakeholders and the SDT believes the responses accurately reflect the feelings of industry to the intended question. The slight majority of stakeholders agree with the requirement while some stakeholders indicated that they do not feel the requirement is technically achievable. Based on the comments received, no major changes were made to Requirement R6 (now R5).

The GVSDT proposed voltage ride-through tables for High Voltage Ride Through (HVRT) and Low Voltage Ride Through (LVRT) time durations in Attachment 2. These tables a specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Stakeholders were asked if they agree with the proposed times in the tables. A majority of stakeholders agreed with the time values. Many of those that responded in the negative to the question indicated that they felt the 600 seconds duration was acceptable but had other concerns with the standard. No substantive suggestions were made for revising R6. As a result, the GVSDT did not make any changes to Attachment 2.

Index to Questions, Comments, and Responses

1. There are two new terms proposed in this standard. "Frequency Excursion" and "Voltage Excursion". The former defined as an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz. The latter defined as an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage. Do you agree with these new terms and their definitions? If not, please explain. 17

2. Requirements R1 and R2 detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Does the current draft of these two requirements, including footnote 1, clarify that a Generator Owner is not required to have protective relaying installed or set for these functions? If you do not believe the requirement is clear, please provide alternative language to clarify the intent. 30

3. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language. 50

4. Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. 67

   Please provide along with your comment, what you believe the timeframe is needed to implement this requirement. 67

5. The voltage ride-through Tables HVRT and LVRT Duration in Attachment 2, specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Do you agree with this time duration value? If not, please provide an alternative value and supporting information in the comments. 84

6. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain... 98

Additional Comments submitted by PacifiCorp – Sandra Shaffer:................................. 150

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	David Thorne	Pepco Holdings Incand Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3
2.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Member	Organization	Region	Segment
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
3.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Jesus Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Marcela Caballero	IID	WECC	5
5.	Cathy Bretz	IID	WECC	6

				1	2	3	4	5	6	7	8	9	10
4.	Group	Jason Marshall	ACES Power Members						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Jones	AEPCO/SWTC	WECC	1, 3, 5
2.	Mohan Sachdeva	Buckeye Power	RFC	3, 4, 5

				1	2	3	4	5	6	7	8	9	10
5.	Group	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
2.	Pat G. Harrington	BC Hydro and Power Authority	WECC	3
3.	Clement Ma	BC Hydro and Power Authority	WECC	5
4.	Daniel O'Hearn	BC Hydro and Power Authority	WECC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Joe Spencer - SERC staff	SERC Generation Sub-committee (GS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Camilletti	Santee Cooper	SERC	
2.	Sam Dwyer	Ameren Missouri	SERC	
3.	David Thompson	TVA	SERC	
4.	Robin Wells	LG&E/KU	SERC	
5.	Chris Georgeson - chair	Progress Energy	SERC	
6.	Chris Schaeffer	Duke Energy	SERC	
7.	Dale Goodwine	Duke Energy	SERC	
8.	Brad Haralson	AECI	SERC	
9.	Kumar Mani	Progress Energy	SERC	
10.	Joe Spencer	SERC Reliability Corp	SERC	

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Tim Brown	Idaho Power - Power Production					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Guy Colpron	Idaho Power	WECC	5
2.	Mark Pfeifer	Idaho Power	WECC	5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jonathan Hayes	SPP Reliability Standards Develpment Team		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clem Cassmeyer	Western Farmers	SPP	1, 3, 5
2.	Craig Henry	Oklahoma Gas and electric	SPP	1, 3, 5
3.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4.	Louis Guidry	CLECO	SPP	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Lynn Schroeder		Westar energy	SPP 1, 3, 5, 6										
6. Mahmood Safi		OPPD	SPP 1, 3, 5										
7. Robert Cox		Lea County Electric	SPP										
8. Thomas Hestermann		Sunflower Electric	SPP 1										
9. Valerie Pinamonti		AEP	SPP 1, 3, 5										
10. Robert Rhodes		Southwest Power Pool	SPP 2										
9.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5
14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Mike Garton	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
2.	Louis Slade		RFC	5, 6
3.	Mike Garton		NPCC	5
4.	Michael Gildea		MRO	5
5.	Matthew Woodzell		SERC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Joe Spencer - SERC staff	Dynamics Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Camilletti	Santee Cooper	SERC	
2.	Sam Dwyer	Ameren Missouri	SERC	
3.	David Thompson	TVA	SERC	
4.	Robin Wells	LG&E/KU	SERC	
5.	Chris Georgeson - chair	Progress Energy	SERC	
6.	Chris Schaeffer	Duke Energy	SERC	
7.	Dale Goodwine	Duke Energy	SERC	
8.	Brad Haralson	AECI	SERC	
9.	Kumar Mani	Progress Energy	SERC	
10.	Joe Spencer	SERC Reliability Corp	SERC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Duge	FE	RFC	5
2.	Ken Dresner	FE	RFC	5
3.	Mike Williams	FE	RFC	5
4.	Brian Orians	FE	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Rene Free	Santee Cooper	SERC	1
3.	Bridget Coffman	Santee Cooper	SERC	1
4.	Paul Camilletti	Santee Cooper	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Mueller	PSE&G	RFC	3
2.	Ken Brown	PSE&G	RFC	1
3.	Mikhail Falkovitch	PSEG Fosssil	RFC	5
4.	Peter Doln	PSEG ER&T		6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Annette Bannon	PPL Supply					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
2.		PPL Brunner Island, LLC	RFC	5
3.		PPL Holtwood, LLC	RFC	5
4.		PPL Martins Creek, LLC	RFC	5
5.		PPL Montour, LLC	RFC	5
6.	Dave Gladey	PPL Susquehanna, LLC	RFC	5
7.	Leland McMillan	PPL Montana, LLC	WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	Utilities Commission, City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

				1	2	3	4	5	6	7	8	9	10
18.	Group	Mallory Huggins	NERC Staff Technical Review Team										

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
19.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3
2.	Chuck Matthews	BPA, Transmission Planning	WECC	1
3.	Erika Doot	BPA, Generation Support	WECC	3, 5, 6
4.	Mike Alder	BPA, Federal Hydro Projects	WECC	5

				1	2	3	4	5	6	7	8	9	10
20.	Individual	David Thompson	TVA - GO					X					
21.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
22.	Individual	Bo Jones	Westar Energy	X		X		X	X				
23.	Individual	David Youngblood	Luminant Power					X					
24.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
25.	Individual	Scott Sweat	Westinghouse					X					
26.	Individual	Antonio Grayson	Southern Company	X		X			X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	Edward Cambridge	APS	X		X		X					
29.	Individual	Michael Goggin	American Wind Energy Association								X		
30.	Individual	Samuel Reed	Tri-State Generation and Transmission, Inc.	X				X					
31.	Individual	Bob Casey	Georgia Transmission Corporation	X									
32.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					
33.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
34.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
35.	Individual	John Bee on behalf of Exelon	Exelon	X		X		X					
36.	Individual	Eric J Anderson	New York Power Authority	X		X		X					
37.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
38.	Individual	Tom Flynn	Puget Sound Energy	X		X		X					
39.	Individual	Jeanie Doty	Austin Energy					X					
40.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
41.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
42.	Individual	James R. Keller	We Energies			X	X	X					
43.	Individual	Linda Horn	We Energies			X	X	X					
44.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
45.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
46.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
47.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
48.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
49.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
50.	Individual	Kathleen Goodman	ISO New England Inc.		X								
51.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
52.	Individual	Brad Jones	Luminant Energy						X				
53.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
54.	Individual	Kirit Shah	Ameren	X		X		X	X				
55.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
56.	Individual	Larry Grimm	Texas Reliability Entity										X
57.	Individual	Anthony Jablonski	RFC										X
58.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
59.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
60.	Individual	Gary Chmiel	GE Energy										
61.	Individual	Barry J Skoras	PPL Electric Utilities	X									
62.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
63.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
64.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
65.	Individual	Armin Klusman	CenterPoint Energy	X									
66.	Individual	Dan Hansen	GenOn Energy					X					

1. There are two new terms proposed in this standard. "Frequency Excursion" and "Voltage Excursion". The former defined as an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz. The latter defined as an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage. Do you agree with these new terms and their definitions? If not, please explain.

Summary Consideration: Stakeholders were evenly divided regarding the proposed definitions. The majority of "No" votes disagreed with the voltage excursion portion of the question while there was only one vote disagreeing with the frequency excursion portion.

After reviewing all comments the SDT made the following changes:

1. **The two new terms proposed in the standard were removed. The voltage and frequency excursion values are now located in the requirements where they apply.**
2. **Attachment 1 (Off Nominal Frequency Capability Curve) was revised to clarify the "no trip" zone.**
3. **Attachment 2 (Voltage Ride-Through Time Duration Curves) has been clarified. The per unit voltage base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES). In addition, the definition was modified to include the phrase, "voltages in the curve assume minimum phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum phase-to-ground or phase-to-phase voltage for the high voltage duration curve."**

Organization	Yes or No	Question 1 Comment
Occidental Chemical	Negative	1. There are two new terms proposed in this standard. "Frequency Excursion" and "Voltage Excursion". The former defined as an exceedance of system frequency beyond a continuous operating band; 60Â±0.5 Hertz. The latter defined as an exceedance of system voltage beyond a continuous operating band; Â±5% of scheduled voltage. Do you agree with these new terms and their definitions? If not, please explain. No: Comments: Ingleside Cogeneration LP agrees that the continuous frequency specification is unambiguous and reasonable. However, the voltage operating specification needs to tie directly to the Transmission Operator's voltage or Reactive Power schedule developed in compliance with VAR-001. We believe this was the drafting team's intent, but the definition does not clearly indicate that this is the case.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		

Organization	Yes or No	Question 1 Comment
The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	Comment (1) Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary. (2) Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **With regard to comment 1, R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.** **With regard to comment 2, R4 was revised to remove the probability of a unit (including auxiliaries) remaining connected to the system. R4 takes into consideration a voltage recovery profile at the point of interconnection using the dynamic study results from the transmission planner/coordinator. Thank you for your response. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied.**		
Pepco Holdings Incand Affiliates	No	Suggest replacing the term "scheduled voltage" with "nominal operating voltage". Voltage schedules may change over time, whereas "nominal" or "rated" voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, "rated" or "nominal" voltage.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.**		
Northeast Power Coordinating Council	No	Any requirement that requires reporting based on a deviation greater than a specified threshold, that threshold should be included in that requirement, refer to R5 as an example. With those stipulations, those

Organization	Yes or No	Question 1 Comment
		new terms are not needed.
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
SERC Generation Sub-committee (GS)	No	The SERC generation sub-committee (GS) believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to "... exceedance of system voltage beyond the applicable voltage schedule."
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
Idaho Power - Power Production	No	Basing the voltage excursion definition on scheduled voltage is troublesome, as "scheduled" voltage can change over time, and in some cases, varies seasonally. Protection and limiter settings are not, and should not, be adjusted to address varying schedules. That said, simply using nominal voltage instead of scheduled voltage is probably not the answer either, as it is not unusual to have POI scheduled voltages of 1.05 pu or higher.
Response: Thank you for your comments. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.		
SPP Reliability Standards Develpment Team	No	We believe that +-5% is ok for normal operating conditions but this doesn't address contingencies being taken or a time frame. The curve in attachment 2 doesn't seem to correspond with the definition as proposed. We are also unclear about the term continuous. We think this means from 0 to infinite. This graph indicates at 600s one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria shows that during a contingency we can operate at a +5% -10% bandwidth.
Response: Thank you for your comments. **The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that**		

Organization	Yes or No	Question 1 Comment
they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. **The standard was not intended to apply to contingency operations.**		
Dynamics Review Subcommittee	No	Exceedance implies that the frequency is greater than desired frequency. Since the intent is to identify frequencies greater or less than a specified amount from the desired frequency, replacing the word “exceedance” with “deviation” and “beyond” with “outside” seems more appropriate.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The frequency chart was revised to clarify the “no trip” zone.		
Santee Cooper	No	We’re not sure these definitions serve a useful purpose, since, later on in the standard, these excursions are defined by the curves in the attachments.
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
NERC Staff Technical Review Team	No	NERC staff believes it is unnecessary to define these terms to achieve the reliability objective of this standard. We further note that the proposed definitions of these terms are in conflict with usage of the phrases frequency excursion and voltage excursion in other standards and a defined glossary term. A review of existing NERC standards and the NERC glossary identifies the following inconsistencies:(1) Standard BAL-003-0.1b “requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting.” Events identified for use in analyzing and setting requirements for frequency response are associated with frequency deviations of less than Â±0.5 Hz, and not necessarily deviating from 60 Hz.(2) Standard EOP-004-1 requires reporting for “any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in sustained voltage excursions equal to or greater than Â±10%.”(3) Standard PRC-006-1, refers to “system frequency excursions below the initializing set points of the UFLS program.” The initializing setpoints of UFLS programs vary by region.(4) The defined term, Disturbance Monitoring Equipment, includes “Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz - 3 Hz) oscillations and abnormal frequency or voltage excursions.”We also observe inconsistency within the draft PRC-024-1 which refers to “a Frequency Excursion defined by the curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2,” which is in conflict with the proposed definitions.Given the range of contexts in which the phrases frequency excursion and voltage excursion are used we believe it is most appropriate that each standard identify the excursions of interest in the context of that standard, rather than establishing defined terms with specific numerical values.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
TVA - GO	No	TVA believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to "... exceedance of system voltage beyond the applicable voltage schedule
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
Westar Energy	No	We agree with the frequency excursion defined as +/-0.5Hz.We agree that Â±5% is appropriate for normal operating conditions. However, this does not address contingencies or timeframes. The SPP regional criteria allows for a +5% to -10% change from nominal voltage on load serving buses under single contingency conditions. The Voltage Ride-Through Time Duration Curve in Attachment 2 does not appear to correspond with the proposed definition. The Voltage Ride-Through Time Duration Curve in Attachment 2 indicates that at 600 seconds, one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria states that we can operate at a +5% to -10% of nominal voltage on load serving buses during a contingency. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of this definition. We propose that the SDT consider defining continuous. We are unclear if continuous means from zero to infinite.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. **The standard was not intended to apply to contingency operations.**		
Progress Energy	No	PE suggests using the term "exceeding" rather than "exceedance". PE furthermore believes that 60 HZ +/- 0.5 Hz is appropriate but does not agree that +/- 5% for voltage is an appropriate bandwidth for "normal". Any threshold must agree with VAR-002. Along with a clarification of what a voltage schedule is (i.e. target, bandwith).
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values		

Organization	Yes or No	Question 1 Comment
are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
PacifiCorp	No	The definition for Voltage Excursion provided in the most recent draft of PRC-024-1 is closer to the definition of a voltage deviation. The Voltage Excursion definition should be modified to include a time duration component, e.g. “fast transition” of system voltage beyond the continuous operating band of Â±5% of scheduled voltage. Otherwise, a very slow voltage transition could be considered a voltage excursion if it exceeded the voltage band, thereby missing the intent of and time frames set forth in Attachment 2. A similar comment is applicable for Frequency Excursion. A transition time duration is key to the definition of both Voltage Excursion and Frequency Excursion due to the significant impact that these parameters can have on a generating facility.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. The fast transition is considered with the transmission planner/coordinator performing a dynamic study that provides a voltage recovery profile.**		
Tri-State Generation and Transmission, Inc.	No	We don't think exceedance is a word. Suggest changing it to "operating outside of a continuous range of 60+/-0.5 Hz".We don't agree with using the phrase "scheduled voltage" as is staed in the question, but the actual standard uses "rated voltage" with which we do agree.
Response: The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.**		
Exelon	No	The definitions provided for Frequency Excursion and Voltage Excursion are not consistently applied throughout the Standard. Several of the uses of the term “excursion” (R1.2, R5.1, R5.2, R6, etc...) refer to the graphs in Attachments 1 and 2, which are based on time characteristics. Exelon agrees that 60 HZ +/- 0.5 Hz is reflective of a (normal) continuous operating band; however, the voltage +/- 5% is not necessarily a (normal) continuous operating band of "scheduled voltage". The "scheduled voltage" should be consistent with VAR-001 and VAR-002. VAR-001 Requirement R.4 states:"Each Transmission Operator shall specify a

Organization	Yes or No	Question 1 Comment
		voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator."VAR-002 Requirement R.2 states:"[Unless exempted by the Transmission Operator] each Generator Operator shall maintain the generator voltage or Reactive Power output ... as directed by the Transmission Operator."Suggest that the definition for Voltage Excursion is revised to state "an exceedance of system voltage beyond (i.e., outside) nominal operating band as determined by the Transmission Operator"
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
Independent Electricity System Operator	No	We generally agree with these definitions, but do not see the need to specify the band values, i.e. Â±0.5 Hertz and Â±5%, in them. The two definitions should stay clear of any specific values, which can be specified in the standard, to remain valid if and when the band values vary.
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
Wisconsin Electric	No	The system can operate without problems within +/- 5% of nominal system voltage under normal conditions. Generator capability curves allow for continuous operation between 95% and 105% of rated voltage. Therefore, the operating band for voltage needs to be expanded beyond +/-5%, perhaps as high as +/- 10%.
Response: Thank you for your comments. The voltage chart (Attachment 2) may be more stringent in your region and can be modified.		
We Energies	No	The system can operate without problems within +/- 5% of nominal system voltage under normal conditions. Generator capability curves allow for continuous operation between 95% and 105% of rated voltage. Therefore, the operating band for voltage needs to be expanded beyond +/-5%, perhaps as high as +/- 10%.
Response: Thank you for your comments. The voltage chart (Attachment 2) may be more stringent in your region and can be modified.		
Duke Energy	No	We are not sure what is the purpose of the voltage excursion definition in this standard. Is excursion measured versus scheduled voltage, or equipment rating?
Response: Thank you for your comments. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the		

Organization	Yes or No	Question 1 Comment
system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
US Army Corps of Engineers	No	
Western Electricity Coordinating Council	No	WECC is requesting a regional variance to Requirement 1 that reflects the generator performance requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan. WECC's continuouse operations zone is between 59.4 hZ and 60.6 Hz. Therefore, WECC will need a regional definition of Frequency Excursion to be an exceedance of system frequency beyond a continuous operating band of 60Â±0.6 Hertz.
Response: Thank you for your comments. The SDT team discussed this and a regional variance has been added.		
ISO New England Inc.	No	The term “system voltage” is unclear as to where it is measured. Attachment 2 shows the curve based on voltage at the Point of Interconnection, yet R2.1 refers to voltage at the generator terminals. ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the “Point of Interconnection-Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. The time duration curve shown in Attachment 2 will need to modified to be consistent with this range for the times at and beyond 600 seconds to be consistent with this change.
Response: Thank you for your comments. **R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection. A transmission planner can provide a dynamic study that reflects the voltage recovery profile to be used by the generator owner to assess generator protective relay(s) operating characteristics.** **Attachment 2 may be more stringent in your region and can be modified.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP agrees that the continuous frequency specification is unambiguous and reasonable. However, the voltage operating specification needs to tie directly to the Transmission Operator’s voltage or Reactive Power schedule developed in compliance with VAR-001. We believe this was the drafting team’s intent, but the definition does not clearly indicate that this is the case.
Response: Thank you for your comments. **The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that**		

Organization	Yes or No	Question 1 Comment
they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
Luminant Energy	No	The frequency is acceptable but the voltage band is confusing. The generator operating range is +/- 5% from rated at full load. Luminant recommends that the voltage excursion be referenced to generator rated voltage.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
Ameren	No	Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. **R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.**		
Consolidated Edison Co. of NY, Inc.	No	Requirement 1, paragraph 1.1 requires that units remain connected, 1.1. When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive. Yet the definitions of Frequency and Voltage Excursion could be misinterpreted to apply only to trips occurring when the frequency or voltage at the time of trip-out was outside the normal operating range. We do not believe that it was the intent of the drafting team to exempt units which might trip within the normal operating range during an event. Therefore, we propose to change the focus from Excursions outside a normal operating range to variations within and outside that normal operating range, out to specified limits (the operating envelope). We suggest that the term Frequency and Voltage Excursion be re-defined as variations follows: Frequency [delete “Excursion” add “Variation”] - an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] frequency within a planned continuous operating band, e.g., 60Â±0.5 Hertz, and beyond a planned continuous operating band to specified limits (Attachment 1). Voltage [delete “Excursion” add “Variation”] - an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] voltage within a planned continuous operating band, e.g., 0.95 to 1.00 per unit, and beyond a planned continuous operating band to specified limits (Attachment 2). This definition includes certain types of specified variations: (a) Operation within an allowable normal operating bands,

Organization	Yes or No	Question 1 Comment
		such as voltage variations within an allowed Â±5% of scheduled voltage, e.g. from 0.95 to 1.00 per unit. (b) Operation within a modified scheduled operating band voltage change, such as with the range around a scheduled nominal voltage reduction during a brown-out, where the allowed voltage operating band is intentionally reduced, and (c) Operation up to limits specified and/or referenced in MOD-026. For example, voltage variations either within or outside of the scheduled operating band of 0.95 to 1.05 per unit of nominal, e.g., a 328-362 kV operating band around a 345 kV scheduled nominal voltage. We propose to change the Purpose wording (and similar wording elsewhere) as follows: Purpose: Ensure generating units remain connected during frequency and voltage [delete "excursions" and add "variations"] and ensure expected generating unit performance during frequency and voltage [delete "excursions" and add "variations"] is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. **Attachment 1 was modified to clearly show the "no trip" zones. The voltage ride-through (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.** **The standard was not intended to apply to contingency operations.**		
Hydro-Quebec TransEnergie	No	Mostly, HQT's frequency and voltage curves are more stringent for generators, as the area for no trip zone is wider. However, the following points on those curves of attachment 1 and attachment 2 are too stringent and we ask to consider these modifications: o On the frequency curve, for wind or thermal generation only, the no trip zone between 0 and 5 seconds should be limited to an over frequency of 61,7 hz. o On the voltage curve, the no trip zone should be restricted as follow: ï,§ Between 1 and 2 seconds, to 0,75 pu, ï,§ Between 2 and 3 seconds, to 0,85 pu.
		(1) Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary. (2) Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable.
Response: Thank you for your comments. **The frequency chart may be more stringent in your region and can be modified.** **R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the**		

Organization	Yes or No	Question 1 Comment
point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection. **R4 was revised to remove the probability of a unit (including auxiliaries) remaining connected to the system. R4 takes into consideration a voltage recovery profile at the point of interconnection using the dynamic study results from the transmission planner/coordinator.**		
PPL Supply	Yes	1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary.2. The need for excursions as severe as those of Att.2 should be confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/- 1.74%) would be considered abnormal for our system (PJM).
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. The chart may be more stringent for your region based on the transmission planner specifications.**		
American Electric Power	Yes	Where these definitions appear to be referenced in the standard (R5 and R6), they seem to be at odds with Attachments 1 and 2. Either the attachments should be used and remove the definitions, or instead, the definitions should be used and remove the references to the attachments in R5.1 and R5.2 and R6.We recommend removing the definition of “Frequency Excursion” and retaining Attachment 1 subject to our comments given elsewhere in this document. We recommend keeping the “Voltage Excursion” definition and eliminating Attachment 2 based on our comments elsewhere in our response.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
PPL Electric Utilities	Yes	1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary.2. The need for excursions as severe as those of Att.2 should be

Organization	Yes or No	Question 1 Comment
		confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/- 1.74%) would be considered abnormal for our system (PJM).
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. The chart may be more stringent for your region based on the transmission planner specifications.**		
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
BC Hydro and Power Authority	Yes	
MRO's NERC Standards Review Forum	Yes	
Electric Market Policy	Yes	
LG&E and KU Energy	Yes	
FirstEnergy	Yes	
Public Service Enterprise Group	Yes	
Florida Municipal Power Agency	Yes	
Arizona Public Service Company	Yes	
Luminant Power	Yes	
Westinghouse	Yes	

Organization	Yes or No	Question 1 Comment
Southern Company	Yes	
American Wind Energy Association	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Puget Sound Energy	Yes	
Austin Energy	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
South Carolina Electric and Gas	Yes	
RFC	Yes	
Tacoma Power	Yes	
GE Energy	Yes	
American Transmission Company	Yes	

2. Requirements R1 and R2 detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Does the current draft of these two requirements, including footnote 1, clarify that a Generator Owner is not required to have protective relaying installed or set for these functions? If you do not believe the requirement is clear, please provide alternative language to clarify the intent.

Summary Consideration: Stakeholders agreed that footnote 1 does clearly state that a Generator Owner is not required to have protective relaying installed or set for frequency or voltage protection. Many of the stakeholders made additional comments beyond the scope of the question regarding the intention of Requirements R1, R2, and R3. In response, the SDT made the following changes:

1. The Requirement Parts were revised in Requirement R1. Part 1.5 was moved into the body of R1. The requirement now reads:

> **"R1. Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not trip within the "no trip zone" of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. . [Violation Risk Factor: High] [Time Horizon: Long-term Planning]**
>
> **1.1. A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec.**
>
> **1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."**

2. Requirement Part 2.1.1 was removed from Requirement R2. The body of the requirement and the remaining Parts were modified to clarify intent. The requirement now reads:

> **"R2. Each Generator Owner that has generator voltage protective relaying1 activated to trip its new or existing generating unit or generating plant shall set its protective relaying such that it does not trip as a result of a voltage excursion (at the point of interconnection) that remains within the "no trip zone" of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit2 or generating plant.: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]**

2.1. When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. If a Transmission Planner's study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner's voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.

2.1.2. Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2.

2.1.3. If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

3. Requirement R3 was changed to clarify the intent of non-protection system limitations and when such limitations must be addressed. The requirement now reads:

"3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

- **The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.**

- **The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard)."**

Organization	Yes or No	Question 2 Comment
PacifiCorp	Negative	(1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without

Organization	Yes or No	Question 2 Comment
		the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. **It is not practical to define the excursions at the generator terminals due to the differences in generator, step-up transformer, and system characteristics. Other voltage ride through standards (e.g. FERC Order 661A and various European standards) all define the voltage profile at the transmission level (where the event occurs).** (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function. R1.1.5 does not require tripping for a frequency rate of change over the stated value, but does allow that tripping even if the frequency magnitude is still within the No Trip Zone.** o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **Part 2.1.1 states "… transmission system zone 1 faults…" The SDT believes this makes it clear that it does not involve the generator or distribution system.** (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditions within 95% and 105% of rated generator terminal voltage the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to PRC-024 Attachment 2. 2.1.3 Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" in PRC-024

Organization	Yes or No	Question 2 Comment
		Attachment 2. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2. **The SDT has revised the wording in the subsections of Requirement R2 to make the intent clearer. Section 2.1.1 has been removed. Section 2.1.3 now says "Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2." Section 2.1.4 now says" If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2."** (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **The SDT has modified PRC-024 Attachment 1 to accommodate the WECC regional requirements.**
Response: Thank you for your comments. See specific responses above.		
Occidental Chemical	Negative	2. Requirements R1 and R2 detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Does the current draft of these two requirements, including footnote 1, clarify that a Generator Owner is not required to have protective relaying installed or set for these functions? If you do not believe the requirement is clear, please provide alternative language to clarify the intent. No: Comments: Requirement R1 from Ingleside Cogeneration's perspective could lead to a double-infraction for the same incident. For example a single improper relay operation for an underfrequency transient would lead to a violation of both R1.2 and R1.3. It should be sufficient to specify that relays must be set in conformance with the off-frequency excursions provided in PRC-024 Attachment 1. Also, there must be some logical limit to the Hz/Second ride-through threshold specified in R1.5. As the requirement is written, even a large-magnitude frequency transient must not cause relays to operate as long as the frequency rate of change is slow. If for example, the interconnection frequency dropped to 55 Hz at a rate lower than 2.5 Hz/Second, R1.5 seems to require that the generator would remain connected to the BES. For the record, R2 seems to be more logically constructed - and lists reasonable exceptions to voltage relay settings. Ingleside Cogeneration LP recommends the drafting team to take a similar approach on R1.
Response: Thank you for your comments. The SDT has removed the subparts of Requirement R1. The intent of part 1.5 of Requirement R1 was to allow tripping if the rate of change of frequency exceeded 2.5 Hz/sec, even if the absolute frequency were still within the No Trip Zone of PRC-024		

Organization	Yes or No	Question 2 Comment
Attachment 1. The wording has been revised to clarify the intent and incorporated into the body of the Requirement. It now says" Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility shall set such protective relaying not to trip per PRC-024 Attachment 1 unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."		
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	4)Requirement R1.5 is unclear. Are the relays not allowed to trip regardless of frequency if the rate of change is less than 2.5 Hz/sec. If so, the existing generator relays don't have the capability to block for this condition. It would seem undesirable to block for this condition and risk damage to generation. **The intent of part 1.5 of Requirement R1 was to allow tripping if the rate of change of frequency exceeded 2.5 Hz/sec, even if the absolute frequency were still within the No Trip Zone of PRC-024 Attachment 1. The wording has been revised to clarify the intent and incorporated into the body of the Requirement. The wording now states: "Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."** (5)R2.1.3 needs to be more specific. With multiple outlet lines, generators may only be tripped for certain lines or breaker failure conditions. Generators would only be allowed to trip in the "no trip zone" for the specific conditions of the SPS or RAS schemes? **The SDT agrees that the generators would be allowed to trip in the no trip zone for the specific condition of a SPS or RAS scheme and believes the existing wording conveys that intent.**
Response: Thank you for your comments. See specific responses above.		
Lower Colorado River Authority; Platte River Authority; Snohomish County PUD No. 1	Negative	o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. **The posted curves in PRC-024 Attachment 1 match PRC-006 Attachment 1 expectations for generator tripping. Modifications to PRC-024 Attachment 1 have been made to**

Organization	Yes or No	Question 2 Comment
		accommodate regional variations in WECC and the Quebec Interconnection. o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. However language for zone 1 faults sets to remove the generator before 9-cycles. **Requirement R2, part 2.1.1 had been removed.** o Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? o **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.**
Response: Thank you for your comments. See specific responses above.		
Black Hills Corp	Negative	As drafted R1 confilists with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan) and could potentially result in a negative reliability impact if enforced in the Western Interconnect. **Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** The language of R2, part 2.1.1 is confusing and needs to be clarified. **The wording of Requirement R2, part 2.1.1 had been removed.**
Response: Thank you for your comments. See specific responses above.		
Avista Corp.; BrightSource Energy, Inc.; Chelan County Public Utility District #1; City of Farmington; City of Redding; Colorado Springs Utilities; City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power; Cogentrix Energy, Inc.; Idaho Power Company; Los Angeles Department of Water & Power; Pacific Gas and Electric Company; Salt River Project; South California Edison Company; Tacoma Public	Negative	As drafted, Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements as identified in the WECC Off-Nominal Load Shedding Plan must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** The language of Requirement R2, part 2.1.1 is confusing and needs to be clarified. **The wording of Requirement R2, part 2.1.1 had been removed.**

Organization	Yes or No	Question 2 Comment
Utilities; Western Area Power Administration; Western Electricity Coordinating Council; Seattle City Light		
Response: Thank you for your comments. See specific responses above.		
MEAG Power	Negative	Comment o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Â Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan.Â This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion.Â Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2"Â a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan.Â Â **Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. Â However language for zone 1 faults sets to remove the generator before 9-cycles. **The wording of Requirement R2, part 2.1.1 had been removed.** o Regarding generator's non-protection Â system equipment limitations exemption expiration for upgrades of Â =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.** o The response content for R4 is ambiguous regarding what the written response should contain. **The SDT has removed Requirement R4.** o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping? **A note has been added to PRC-024 Attachment 1 to indicate that tripping is allowed on the lines.**

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. See specific responses above.		
Orlando Utilities Commission; Snohomish County PUD No. 1	Negative	Comment o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. **The posted curves in PRC-024 Attachment 1 match PRC-006 Attachment 1 expectations for generator tripping. Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. However language for zone 1 faults sets to remove the generator before 9-cycles. **The wording of Requirement R2, part 2.1.1 had been removed.** o Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.** o The response content for R4 is ambiguous regarding what the written response should contain. **The SDT has removed Requirement R4.** o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping? **A note has been added to PRC-024 Attachment 1 to indicate that tripping is allowed on the lines.**
Response: Thank you for your comments. See specific responses above.		
Florida Municipal Power Pool	Negative	Considering R1, many generators have speed protection embedded in control systems (e.g., a GE Mark V or VI), is that included in footnote 1 to the requirement in the phrase: "multi-function protective devices or

Organization	Yes or No	Question 2 Comment
		protective functions within excitation controls that directly trip or provide tripping signals to the generator based on frequency or voltage inputs"? **The SDT agrees and has revised the wording in the footnote to clarify the intent.** In R2, does "voltage protective relaying" include station service protection, such as motor-contactors? **Requirement R2 has been revised to clarify that it is generator protective relaying. Auxiliary systems are not included.** The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment". **Protective relays are one element in a protection system. The SDT does not believe there is an inconsistency.**
Response: Thank you for your comments. See specific responses above.		
Muscatine Power & Water	Negative	In Requirement 1, Requirement 2 and footnote 1 it is not clear because control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under Requirement 3, which covers equipment limitations either. **The SDT agrees and has revised the wording in the footnote to clarify the intent.** For Requirement 5, if design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements. **The SDT has extended the implementation of Requirement R5 to six years to allow for the development of designs that meet the Requirement.**
Response: Thank you for your comments. See specific responses above.		
Balancing Authority of Northern California NCR11118; Sacramento Municipal Utility District	Negative	We commend the drafting team's efforts with the Verification of Models and Data for Generator Excitation and Control System Functions and Plant Volt/VAr Control Functions. However, the following comments regarding PRC-024-1 are currently prohibiting an affirmative position: Requirement R1 mandates the generator off-nominal frequency to requires that the GO set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the

Organization	Yes or No	Question 2 Comment
		Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. Clarification for allowable tripping options of points on the Attachment 1 curve other than the 59.5 Hz and 60.5 Hz values are necessary. **The posted curves in PRC-024 Attachment 1 match PRC-006 Attachment 1 expectations for generator tripping. Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** The language of Requirement R2, part 2.1.1 is confusing and needs to be clarified. According to Attachment 1 capable generators are required to stay connected at a minimum for 9 cycles for the zone 1, three phase faults. Regarding sub-requirement 2.1.1. where: for three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, not to exceed 9 cycles. This appears to be addressing clearing times for the transmission elements and is not applicable to the generator owner. As PRC-024-1 is only applicable to the GO, either the applicability needs to be expanded to include the TO or sub-requirement 2.1.1 needs to be struck from PRC-024-1 and considered to be included in another standard. **The wording of Requirement R2, part 2.1.1 had been removed.** Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.**
Response: Thank you for your comments. See specific responses above.		
Pepco Holdings Incand Affiliates	No	Footnote 1 does make it clear that the Generator Owner is not required to have frequency or voltage protective relaying. However, in the current draft, reference to footnote 1 appears to have been inadvertently omitted following the phrase "voltage protective relaying" in R2.
Response: Thank you for your comments. A reference to Footnote 1 has been added to Requirement R2.		
SPP Reliability Standards Develpment Team	No	We agree that R1, with the footnote mentioned, makes it clear that the Generator owner would not be required to have protective relaying installed or set for these functions. As for R2 we feel that footnote 1 should also be referenced in R2.
Response: Thank you for your comments. A reference to Footnote 1 has been added to Requirement R2.		
MRO's NERC Standards Review Forum	No	The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or

Organization	Yes or No	Question 2 Comment
		not. This does not seem to be covered under R3 which covers equipment limitations either.
Response: Thank you for your comments. Footnote 1 has been revised to clarify that "…protective functions within control systems that directly trip the generator…" are included. Requirement R3 discusses the limitations of the generating equipment exclusive of protective functions, whether they are protective relays or protective functions in a control system.		
Electric Market Policy	No	The question is confusing because of the phrase "set for these functions." The language in Requirements R1 and R2 as well as footnote 1 suggest that GOs are not required to have the specific relays "installed or activated on its units. If however, the relays are activated then they are required to be "set" pursuant to the standard.
Response: Thank you for your comments. The SDT agrees that the question could have been worded more clearly, but it appears that you understood the intent.		
Dynamics Review Subcommittee	No	It is unclear how an entity can have protective relaying settings for new units. Since "existing units" covers units under construction as specified in footnote 2, "new" implies planned units and thus the associated relaying would also be "planned" not "existing." It appears the word "new" should be deleted from sentence one of R1 and sentence one of R2.
Response: Thank you for your comments. Requirements R1 and R2 apply to both new and existing units. New units (designed, built and operated after Requirement R5 is implemented) must set any protection system functions that are installed and activated so that they meet these requirements.		
LG&E and KU Energy	No	Comments: LG&E and KU Energy recommends the wording be changed for R1/R2 to "Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following..."Or, change from "Each GO" to "GO's that have frequency and voltage protection functions activated to trip a new/existing generation unit."
Response: Thank you for your comments. The SDT has changed the wording to clarify the intent. Requirement R1 now states, in part: "Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility…". Requirement R2 now states, in part: "Each Generator Owner that has generator voltage protective relaying Error! Bookmark not defined.** **activated to trip its new or existing unit or generating plant or generating Facility…".**		
Santee Cooper	No	The sub-requirements of R2 could be read as prescribing exactly where you have to set this relaying. Often our relay set points originate with the OEM and are based on protecting the Generator and Turbine. The finalized curves that originate here should be used as a means to arrive at those settings, but, as long as the settings do not cause the relaying to operate for the ranges in the finalized curves, the requirements should

Organization	Yes or No	Question 2 Comment
		be satisfied (It shouldn't have to be stated that you can set them less stringent, if you can not have the relaying entirely).
Response: Thank you for your comments. The SDT has defined a "no trip zone" for voltage excursions at the generator's point of interconnection. As with any other exercise in relay coordination, it is up to the Generator Owner to determine how much margin to allow when determining the settings of the protection system.		
Florida Municipal Power Agency	No	The term "protective relaying" is confusing in two ways: 1) the footnote is ambiguous as to how it applies; and 2) it calls into question whether this is a "generation Protection System" applicable to PRC-004 and PRC-005 (especially when considering the inconsistent use of "non-protection system equipment" in R3). FMPA suggests the term "safeguard" instead of "protection", e.g., a "frequency safeguard system" to avoid this ambiguity and with a footnote to make more clear that systems like GE Mark VI's are or are not included.Similarly in R2, it is unclear what "voltage protective relaying" is. FMPA suggests using the word "safeguard" instead of "protection". **The word "safeguard" has specific implications to nuclear plants and is not generally used in industry as a substitute for the word "protection".** Also, it is unclear whether station service voltage safeguards are included, such as motor contactors. **For Requirements R1 and R2, the station service system is not included in the scope. However for new facilities, Requirement R5, states that the facility must ride through the excursions, so the station service system would have to be designed and built to achieve this goal.** In addition, "external to the plant" as used in several requirements (e.g., R1, R2 and R6) is ambiguous. We assume that this would also mean beyond any radial connection (e.g., generator lead) to the plant and would suggest changing the term to something like: "caused by an event beyond the point at which the plant is radially connected to the transmission system". **Requirement R1 does not use the words "external to the plant". Requirements R2 and R6 have been revised and now state, in part: " …caused by an event on the transmission system external to the plant…"**
Response: Thank you for your comments. See specific responses above.		
Bonneville Power Administration	No	R2.1.1 - Please clarify/verify: o That the allowable voltage relay trip time is greater than the normal fault clearing time up to a normal clearing time of 9 cycles; **The SDT agrees.** o That tripping is allowed above 9 cycles regardless if it is normal clearing or backup clearing; and, **The SDT agrees.** o That for generators in close proximity the normal clearing time is coordinated to ensure it is no greater than what a specific generator was designed to withstand. **This standard does not specify requirements for the transmission protection system. This coordination should be accomplished through compliance**

Organization	Yes or No	Question 2 Comment
		with NERC standard PRC-001-1.
Response: Thank you for your comments. See specific responses above.		
Progress Energy	No	Requirement R1 subsection 1.5 is not clear as to when rate tripping is acceptable or not. Is it OK to trip at 59.6 Hz if the ROC is > 2.5 Hz or is this ROC trip acceptable only outside the no trip zone.
Response: Thank you for your comments. The intent is that tripping is allowed if the frequency rate of change exceeds 2.5 Hz/sec even if the absolute frequency is within the "no trip zone" defined in PRC-024 Attachment 1. The wording in Requirement R1 has been revised to clarify the intent. It now states, in part: "…Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."		
Exelon	No	Footnote 1 should be added to the Applicability section of the Standard. Suggest that the Applicability section be revised to state "GO shall set applicable protective relaying so as not to impact R1.1, R1.2, R1.3, R1.5, unless exempted by a non-protection system equipment limitation per the exclusion criteria in Requirement R3."
Response: Thank you for your comments. The SDT disagrees that this wording should be added to the Applicability section.		
Puget Sound Energy	No	Please clarify whether rate of change of frequency relaying is required; or alternatively, if the required setting of not less than 2.5 Hz/sec is only applicable IF rate of change of frequency elements are available and enabled.
Response: Thank you for your comments. The SDT believes that Footnote 1 clearly states that the Generator Owner is not required to install or activate any frequency or voltage protection. This would include rate of change of frequency functions. If the Generator Owner does have frequency rate of change protection installed and activated, then it must be set to meet the Requirement R1.		
Great River Energy	No	The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under R3 which covers equipment limitations either. **Footnote 1 has been revised to clarify that control systems are included if they will trip the generator.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.**

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments.		
Ingleside Cogeneration LP	No	Requirement R1 from Ingleside Cogeneration's perspective could lead to a double-infraction for the same incident. For example a single improper relay operation for an underfrequency transient would lead to a violation of both R1.2 and R1.3. It should be sufficient to specify that relays must be set in conformance with the off-frequency excursions provided in PRC-024 Attachment 1. **The SDT has removed the subparts of Requirement R1.** Also, there must be some logical limit to the Hz/Second ride-through threshold specified in R1.5. As the requirement is written, even a large-magnitude frequency transient must not cause relays to operate as long as the frequency rate of change is slow. If for example, the interconnection frequency dropped to 55 Hz at a rate lower than 2.5 Hz/Second, R1.5 seems to require that the generator would remain connected to the BES. **The intent of part 1.5 of Requirement R1 was to allow tripping if the rate of change of frequency exceeded 2.5 Hz/sec, even if the absolute frequency were still within the No Trip Zone of PRC-024 Attachment 1. The wording has been revised to clarify the intent and incorporated into the body of the Requirement which now states, in part: "Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."** For the record, R2 seems to be more logically constructed - and lists reasonable exceptions to voltage relay settings. Ingleside Cogeneration LP recommends the drafting team to take a similar approach on R1. **The SDT has revised the wording in Requirement R1, which now states: "Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility shall set such protective relaying not to trip per PRC-024 Attachment 1 unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec".**
Response: Thank you for your comments. See specific responses above.		
Luminant Energy	No	Recommended that in the Footnote and in R1 indicate generator protective relaying.
Response: Thank you for your comments. The word "generator" has been added as a modifier to "protective relay" in Requirement R1.		
PPL Electric Utilities	No	Recommend the wording be changed for R1/R2 to " Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following..."

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. The SDT has changed the wording to clarify the intent. Requirement R1 now states, in part: "Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility…". Requirement R2 now states, in part: "Each Generator Owner that has generator voltage protective relaying Error! Bookmark not defined. **activated to trip its new or existing unit or generating plant or generating Facility…".**		
Indiana Municipal Power Agency	No	The term "protective relaying" is confusing in a two ways: 1) The footnote needs to clarify how it applies; and 2)the term calls into question whether this is a "generation Protection System" applicable to PRC-004 and PRC-005. **The SDT has revised the standard to use the term generator protection system. This standard does not define the scope of applicable equipment in other NERC standards.** It needs to be made more clear that systems like the GE Mark IV and VI control systems are or are not included. **Footnote 1 has been revised and now states, in part: "…or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit".** R2 is also not clear when using "voltage protective relaying". It is not clear if voltage safeguards on motor contactors are included. **For Requirements R1 and R2, the station service system is not included in the scope. However for new facilities, Requirement R5, states that the facility must ride through the excursions, so the station service system would have to be designed and built to achieve this goal.** The standard also needs to make more clear what "external to the plant" exactly means. **The words "… on the transmission system…" have been added to clarify the intent.**
Response: Thank you for your comments. See specific responses above.		
Alliant Energy Corp. Services, Inc.	Affirmative	While we are voting affirmative on this ballot, we have 2 comments concerning the standard: 1. Standard needs to be clarified such that it is clear whether the no trip zones include or exclude the lines that define the curves. **The SDT has added a note to PRC-024 Attachments 1 and 2 to indicate that the "no trip zones" do not include the lines that define the curves.** 2. R1 - uses the defined term of protective relaying which for other PRC standards does not include excitation controls such as PRC-005, yet there is a footnote attached to the term "protective relaying" that includes excitation controls which trip generators. This can cause confusion on the interpretation of whether controls that trip are considered a protective relay. R1 should be redrafted to state protective relaying and excitation controls instead of attaching a footnote which redefines what in inclusive in the term "protective relaying". **The SDT believes (in consultation with the Protection System Maintenance and Testing SDT) that protection functions in control systems that directly trip a generator are within the scope of PRC-005.**

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. See specific responses above.		
SERC Generation Sub-committee (GS)	Yes	The GS recommends that the applicability section be revised from "GO" to "GO's that have frequency and voltage protection functions activated to trip a new/existing generation unit." **The SDT disagrees that this wording should be added to the Applicability section.** Also, while the GS does, in general, agree with the content of footnote #2 on page 2 (under R1), we believe that this is verbiage is better placed in the implementation plan because it puts commercial considerations into the standard. **The SDT disagrees that this wording would be better placed in the Implementation Plan.**
Response: Thank you for your comments. See specific responses above.		
Idaho Power - Power Production	Yes	Yes, R1 and R2 do make it clear that the GO does not have to install or set these functions however we believe that the standard should clarify better that the standard is applicable to all "voltage-based" protection functions such as the backup impedance function (21) and the voltage controller (51C) or voltage restrained (51V) Overcurrent functions. These functions may operate if not coordinated properly. We do not believe that was made very clear. **The SDT agrees and has revised Footnote 1 to read, in part: "… relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices…"** Particularly for units that fully compliant with this standard, providing an estimate of unit performance during a frequency or voltage excursion is burdensome and unnecessary. If the event is within the parameters of the standard, the planner can rely on the unit staying on, if not, the planner should model the unit as a trip. In particular, we are unaware of any methodology that would be capable of providing an "estimated probability". Protection consistently operates as designed and configured. **The SDT agrees that the "estimated probability" does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.**
Response: Thank you for your comments. See specific responses above.		
Public Service Enterprise Group	Yes	A one-sentence statement should be added stating that the protective relays affected by this standard are only the generator protective relays, not any other relays for the unit and/or facility.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. The word "generator" has been added in Requirement R1 to clarify the intent.		
Southern Company	Yes	1) The footnote is clear, however, the exact meaning of the phrase "non-protective system equipment" limitation in R1 and R2 is not clear. Does this exclude any equipment limitation that is protected by a protective relay? Does this allow tripping using protective relays that are protecting a turbine from underfrequency conditions or a generator or transformer from excessive volts-per-hertz conditions? We feel that a fundamental tenant of reliability includes adequately protecting generating plant equipment from detrimental conditions - a generator owner needs to be allowed to protect its equipment from possible damaging consequences of off-nominal voltage and frequency. **The SDT agrees that protection of generating plant equipment is fundamental. The meaning of the phrase "non-protection system equipment" is that limitations of the protection system itself cannot be used as an exemption from meeting Requirements R1 and R2.** 2) We believe examples of "non-protection system equipment" include, but are not limited to, turbine generators, transformers, feed pump systems/controls, boiler control systems, reactor protection systems, emergency diesel generators, AC motors, pumps, fans, AC motor contactors, auxiliary relays, etc. **The SDT agrees.** 3) Nuclear stations have an approved Setpoint Methodology which governs the process of determining and documenting setpoints for the equipment at that station. This methodology will incorporate some margin between the expected operating condition and setpoint actuation to help ensure proper operation of the unit but provide the necessary protection as well. How was this considered in the development of this standard? **Standard coordination methodologies apply. If "proper operation of the unit" to meet NRC or other nuclear safety needs requires tripping within the No Trip Zone of either PRC-024 Attachment 1 or Attachment 2, this would be considered a legitimate technical limitation.**
Response: Thank you for your comments. See specific responses above.		
American Electric Power	Yes	Although the footnote is worded somewhat awkwardly, it is clear that a Generator Owner is not required to have protective relaying installed or set for these functions. Suggest using "Generator Owners are not required to have... installed or activated on their units". **Thank you for your comments. The SDT has decided to retain the existing wording.**
PacifiCorp	Yes	
American Wind Energy	Yes	

Organization	Yes or No	Question 2 Comment
Association		
Tri-State Generation and Transmission, Inc.	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Dynegy Inc.	Yes	
Austin Energy	Yes	
Independent Electricity System Operator	Yes	
Wisconsin Electric	Yes	
We Energies	Yes	
We Energies	Yes	
Xcel Energy	Yes	
South Carolina Electric and Gas	Yes	
Duke Energy	Yes	
US Army Corps of Engineers	Yes	
Western Electricity Coordinating Council	Yes	

Organization	Yes or No	Question 2 Comment
ISO New England Inc.	Yes	
Ameren	Yes	
RFC	Yes	
Tacoma Power	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
GE Energy	Yes	
American Transmission Company	Yes	
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
BC Hydro and Power Authority	Yes	
NERC Staff Technical Review Team	Yes	
TVA - GO	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 2 Comment
Luminant Power	Yes	
Westinghouse	Yes	

3. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language.

Summary Consideration: The question, in error, contained a reference to R4 rather than R5. As this question is in error, the drafting team will ask this question on the next posting. Some commented as if the question was really about R4, while most commented as if the question was about R5.

Summary of the R4 comments: Either the specific details of the response required by R4 is needed or R4 is not needed due to no reliability impact.

Summary of the R5 comments:

Many entities (8) feel that there is no additional reliability gain in this requirement - the information is not useful - there is little value technically of this information.

Others (5) expressed that it is very difficult, if not impossible, to predict the consistent response of the balance of (a generating) plant to the system excursions shown in Attachment 1 & 2.

Further, 10 companies expressed that it is unlikely that any steam plants will survive for the entire "no trip zones" of the attachments.

Other, less frequent, opinions included the following:

- **R1-R4 adequately fulfill the purpose of the standard.**
- **Standard requirements should be limited to devices that directly respond to the generator V and F – write standard to exclude all aux system equipment.**
- **The TP needs only to know when the protective relaying V-t and F-t will trip the unit so the models can switch the generators off when the simulated V and F levels are reached.**
- **30 days is too short for a response.**

Organization	Yes or No	Question 3 Comment
PacifiCorp	Negative	(5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity

Organization	Yes or No	Question 3 Comment
		and clarity included in MOD-026, Requirement R3.
Response: Thank you for your comments The SDT has removed Requirement R4.		
Occidental Chemical	Negative	3. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language. No: Comments: Ingleside Cogeneration LP assumes this question actually applies to Requirement R5. It is not clear what extra reliability information will be provided to Transmission Planners as long as Generator Owners confirm that their voltage and frequency settings comply with the performance curves in the attachments. It may be valid to require an estimate of performance if the GO identifies a limitation as allowed under R3. Otherwise, the TP should assume generator relays will operate if the magnitude and duration thresholds defined in the attachments are exceeded.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Balancing Authority of Northern California NCR11118; Sacramento Municipal Utility District	Negative	In Requirement 4, the response content is ambiguous regarding what an acceptable response should contain. Consider requiring the response to be similar to the MOD-026-1 R3 response that identifies a technical basis.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Luminant Energy	Negative	R5 would still be required but the study would only involve fault conditions that have trip times less than 45 cycles.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Black Hills Corp	Negative	Suggest rewrite R4 to add specificity as to what must be included in the required written response, similar to

Organization	Yes or No	Question 3 Comment
		the specificity & clarity included in MOD-026, R3.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Lower Colorado River Authority; Platte River Authority; Snohomish County PUD No. 1	Negative	The response content for R4 is ambiguous regarding what the written response should contain. o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping?
Response: Thank you for your comments. The SDT has removed Requirement R4. The SDT has added a note to PRC-024 Attachment 1 to indicate that the lines that define the curves are allowable tripping points.		
Avista Corp.; BrightSource Energy, Inc.; Chelan County Public Utility District #1; City of Farmington; City of Redding; Colorado Springs Utilities; City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power; Cogentrix Energy, Inc.; Idaho Power Company; Los Angeles Department of Water & Power; Pacific Gas and Electric Company; Salt River Project; South California Edison Company; Tacoma Public Utilities; Western Area Power Administration; Western Electricity Coordinating Council; Seattle City Light	Negative	We suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity included in MOD-026, Requirement R3.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Pepco Holdings Incand Affiliates	No	Believe this question is referring to Requirement R5 not R4 as stated in the question. Not sure how useful the R 5.2 probability assessment would be, therefore suggest eliminating that requirement. R 5.1 coupled with the basis requirement in R 5.3 would appear sufficient to quantitatively assess the performance during voltage

Organization	Yes or No	Question 3 Comment
		and frequency excursions. Also, see responses to question #6.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Northeast Power Coordinating Council	No	The reference to "R4" in this question should be R5.
Response: Thank you for your comments. The SDT agrees.		
ACES Power Members	No	Requirement R4 references inquiries regarding equipment limitations that have been identified in R3. This particular question should apply to R5 instead. If applied to R5, the approach in theory seems reasonable.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. Requirement R5 retains the obligation of the Generator Owner to evaluate the time that a generating unit or facility will remain connected following an excursion that is defined by the Transmission Planner.		
BC Hydro and Power Authority	No	The requirement R5 (R4 is a typo in the Question) is ambiguous and redundant. What does "estimating" mean? One could infer that the GOs are actually required to do what TPs are normally doing as part of their studies: estimating (assessing, simulating) the performance of units during frequency or voltage excursions.In order to fulfill requirements R1, R2 and R3 of this standard, GOs have to do engineering analysis and studies to develop adequate protection settings and to assess other non-protection systems and equipment. By declaring compliance GOs commit to keeping their units on-line during defined frequency or voltage excursions. In the case that a GO identifies a particular limitation, they would inform the TPs so that this limitation is taken into account in system studies. Hence, the goal of the standard would be fully met without R5. In light of the above, the requirement R5 should be removed. Technically it is of little value, if any, becoming just an unnecessary burden for GOs. In compliance terms it could be a source of perpetual confusion and disputes.
Response: Thank you for your comments. As stated in the Requirement, the estimate is to be based on experience, event histories, or sound engineering judgment. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		

Organization	Yes or No	Question 3 Comment
SERC Generation Sub-committee (GS)	No	The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
Response: Thank you for your comments. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Idaho Power - Power Production	No	
SPP Reliability Standards Develpment Team	No	The question should mention R5 and not R4. We feel like the planners shouldn't have to request this data and should be supplied for each unit once and again if the characteristics change. We also feel like 30 days might not be appropriate time to gather such information and would suggest that 90 days would be a better time frame for supplying this data.
Response: Thank you for your comments. The SDT agrees that more time should be allowed and has changed the time to 60 days.		
Electric Market Policy	No	Requirement R4 seems to be duplicative of the obligation to notify the same entities under Requirement R3. Perhaps the language in R4 could be clarified to indicate the distinction.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
LG&E and KU Energy	No	: LG&E and KU Energy agrees with the approach but recommends 60 days. Moreover, this appears to be R5, not R4.
Response: Thank you for your comments. The SDT agrees and has changed the time to 60 days.		
Santee Cooper	No	It should be ascertained how and if the TP will use this in TPL-001 analysis. It will be unclear how to demonstrate compliance.
Response: Thank you for your comments. The Requirement is written for the Generator Owner to respond to the requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner). If these entities do not want this information, they are not required to request it.		

Organization	Yes or No	Question 3 Comment
PPL Supply	No	1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5.2. The question above cites “frequency and voltage excursions [emphasis added],” the question 4 below deals with “frequency or voltage excursions,” para. R5.1 states “Frequency Excursion...and a Voltage Excursion” and para. R6 references “Frequency Excursion or Voltage Excursion.” The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. **The SDT has revised section 5.1 to indicate that the frequency excursion and/or voltage excursion are to be defined by the Transmission Planner.** 3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. **The SDT disagrees. Standards MOD-026 and MOD-027 require verification of the excitation and frequency control responses, but do not discuss the ability of a generating unit or facility to remain connected to the grid.** 4. In the event that R5 remains as-is, a standard-specific definition of the word “plant” is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit’s behavior. **The applicability of this standard is to generating units and facilities that meet the NERC Registry Criteria.** 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024. **The SDT expects the Generator Owner to estimate as best as he can the performance of the entire unit or facility based on past experience, event histories, or sound engineering judgment as described in the requirement.**
Response: Thank you for your comments. See specific responses above.		
Florida Municipal Power Agency	No	R4 is missing the VRF and Time Horizon. FMPA recommends “Lower” and “Long-term Planning”.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Bonneville Power Administration	No	R3-R4 - Generator Owners may be unwilling to share proprietary information in response to requests from Reliability Coordinators, Planning Coordinators, Transmission Operators, or Transmission Planners, because of manufacturer restrictions or for other reasons. Should the standard anticipate this issue?

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. The SDT has removed Requirement R4.		
TVA - GO	No	The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
Response: Thank you for your comments. The SDT agrees and feels the comment is a good statement of the rationale for this Requirement. The information provided by the Generator Owner for modeling his facility based on experience, past event histories, or good engineering judgment will allow better modeling of the performance of the facility.		
Arizona Public Service Company	No	AZPS believes this question applies to R5. In any event, this requirement does not add anything to the reliable modeling since most GO(s) will be making a guess, and that does not make the simulation any more accurate.Additionally, the requirement for providing this information within 30 days is unreasonable. It should be at least 90 days. There is no reliability reason for requiring this data within 30 days. These are long range planning studies and modeling data is usually submitted on the annual basis.
Response: Thank you for your comments. The Requirement is written for the Generator Owner to respond to the requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner). If these entities do not believe the information will be of value, they are not required to request it. The SDT agrees that more time should be allowed and has changed the time to 60 days.		
Westar Energy	No	This question better addresses R5 rather than R4. We propose that the SDT team consider revising the 30 day requirement to provide documentation of the equipment limitation to 90 days in R5. We recommend that 90 days is a more appropriate timeframe for supplying this documentation.
Response: Thank you for your comments. The SDT agrees that more time should be allowed and has changed the time to 60 days.		
Luminant Power	No	Luminant believes this standard should only apply to voltage and frequency relay settings.
Response: Thank you for your comments. The SDT disagrees. Restricting the scope to the protection system settings would not meet the intent of FERC Order 693.		
Progress Energy	No	This appears to actually refer to R5. PE submits the comments below with the assumption that this question is directed toward R5:PE agrees with the requirement of R5 in general, but disagrees with the approach to the extent that R5.1 contains two options for GOs’ providing of information regarding voltage excursions, one of

Organization	Yes or No	Question 3 Comment
		which is problematic. Specifically, the requirements of Attachment 2 are too stringent and cannot be used by the majority of GOs, which leaves the second option as the only feasible method. The second option, provision of a voltage profile "at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault described by dynamic simulation provided by the Transmission Planner", puts the responsibility back on the Transmission Planner. Requirement R5 is intended to aid Transmission Planners in providing information on Generator models needed for Transmission Planning analyses, and yet as it exists the only option for provision of the information is a hindrance to Transmission Planners rather than an aid. PE requests that the SDT simplify the language to merely state that GOs have an obligation to provide information that the TPs request.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.		
Westinghouse	No	a. This is for requirement 5 not requirement 4 **The SDT agrees.** b. We cannot evaluate the performance of units during frequency and voltage excursions at the transmission interface point, only at the generator and 6.9kV bus level where the auxiliary equipment interface exists. Therefore, the frequency and voltage excursion profiles would be different than those submitted by the RC, PC, TO or TP. **The SDT agrees that the profiles would be different which requires the Generator Owner to determine how they would translate to the specific facility based on its characteristics.** Also, 30 days is too short to perform a detailed analysis on plant performance during the frequency or voltage excursion. **The SDT agrees that more time should be allowed and has changed the time to 60 days.** Further evaluation would be required for the transformers, turbine and auxiliary equipment to determine satisfactory operation in the long time periods encompassed in the "No Trip Zones". **The SDT agrees that this would be part of the evaluation.**
Response: Thank you for your comments. See specific responses above.		
Southern Company	No	1) This Question is for R5, not R4. **The SDT agrees.** 2) We disagree with this approach due to the uncertainty about how to estimate the performance. The detailed dynamic analysis required to make an estimate of a specific units performance is not reasonable to require. The voltage excursion profile needed for an evaluation is that voltage present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. The protective relays and control equipment susceptible to high/low voltage excursions are located on the low voltage side of the

Organization	Yes or No	Question 3 Comment
		generator step up transformer. Does agreeing with the approach mean the philosophical desire to provide the TP with information or mean agreement with the requirement to provide estimations of the voltage excursion ride-through ability? We agree with the philosophical mantra, but we are not sure if a conclusive determination of a unit ride-through capability is possible. Generation Owners need a curve from Transmission that is referenced to the lowside since that is where the relays/equipment are located. **The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.** 3) Does "estimate of that unit's performance" only include the estimated time duration of 5.1 and probability of remaining connected in 5.2? Or, does it also include things like the estimated generator terminal voltage, MW, MVars, etc. for the duration of the frequency or voltage excursion? This needs to be clear. **The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The Requirement does not mention generator voltage, real power, reactive power, etc.** 4) The 30 days requirement is much too short. There are a large number of systems and components that would first have to be identified as susceptible to responding to these extreme conditions (especially the voltage conditions). Each of these would then require evaluation, including dynamic analysis for systems and components that respond dynamically over these relatively long time periods. This amounts to major study work on a single unit, much less over many units of many different system configurations and designs having equipment of many different manufacturers and vintages. Also, dynamic studies require accurate system and equipment models to produce valid results and the effort to establish accurate models is no simple task. **The SDT agrees that more time should be allowed and has changed the time to 60 days.**
Response: Thank you for your comments. See specific responses above.		
Oncor Electric Delivery Company LLC	No	It is unclear as to what constitutes an estimate of performance.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.		
Exelon	No	This question refers to Requirement R5 not Requirement R4. **The SDT agrees.** The "ride through" criteria should not extend beyond currently used critical clearing time (2nd zone of

Organization	Yes or No	Question 3 Comment
		protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether nuclear units can survive anything beyond this. **The SDT does not believe it is necessary to extend the 0.0 pu voltage portion of PRC-024 Attachment 2 out to the critical clearing time (where this may be slower than 9-cycles). If normally cleared faults are cleared faster than 9-cycles at a specific location, the Generator Owner may use a voltage profile provided by the Transmission Planner for that site in lieu of PRC-024 Attachement 2.** Plants with auxiliary power systems fed directly from the nuclear switchyard would be even more questionable as the transient is not shielded by the generator bus. **The SDT agrees that it is challenging for many existing generation facilities (not just nuclear facilities). That is the reason for Requirement R5 (so the Transmission Planner, et al, have better information on how an existing facility will respond.**
Response: Thank you for your comments.		
Independent Electricity System Operator	No	We believe the SDT meant R5, not R4, unless R4 is a sub-requirement or a part of R3 (which seems to be the case by the way R4 is worded) and a format error resulted in R4 becoming R5. **The SDT agrees and has removed Requirement R4.** We do not support the provision of such an estimate. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3 (which, by the way, should be modified as we suggest below), the TPs can apply the following relevant assumptions:a. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip;b. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2.We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? **The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.**

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. See specific responses above.		
Wisconsin Electric	No	(We believe the relevant requirement for this question is R5).The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard.Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Response: Thank you for your comments. The SDT included Requirement R5 in order to ensure that the information is provided expeditiously. The SDT believes the word "written" (as opposed to "verbal") would include electronic communications as well as hard copies.		
We Energies	No	(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Response: Thank you for your comments. The SDT included Requirement R5 in order to ensure that the information is provided expeditiously. The SDT believes the word "written" (as opposed to "verbal") would include electronic communications as well as hard copies.		
We Energies	No	(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Response: Thank you for your comments. The SDT included Requirement R5 in order to ensure that the information is provided expeditiously. The SDT believes the word "written" (as opposed to "verbal") would include electronic communications as well as hard copies.		
Great River Energy	No	Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the

Organization	Yes or No	Question 3 Comment
		Generator Owner's best interest to be responsive. Thus, this requirement is not necessary.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Duke Energy	No	Should be R5. We question the value of this requirement, and how the TP use the probabilistic information in any TPL analysis. It's unclear how compliance with planning requirements would be demonstrated. The planner needs to know under what voltage/frequency conditions a unit will trip so that when those conditions are attained in the model the unit will be turned off. Generator owners/operators need to make their best efforts to determine the conditions and provide it to their TP's, updating the information as plant design changes occur or operating history indicates the conditions have changed. Having a time estimate as specified in R5.1 does not provide the voltage/frequency threshold that the planner must know so that the unit can be tripped when those conditions occur in the model, no matter what time those conditions occur.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.		
Western Electricity Coordinating Council	No	The question above appears to be referring to R5, not R4. R5 has the requirements for providing estimates of the performance of the units. I have no comments on R5, However, I have the following comment on R4.We agree with the intent of the requirement, but believe that more specificity in what is required in the written response is necessary. As written it could be argued that a simple response from the Generator Owner indicating they received the inquiry was sufficient. Suggest adding detail similar to that included in MOD-026, Requirement 3 that identifies what the response must contain.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP assumes this question actually applies to Requirement R5. It is not clear what extra reliability information will be provided to Transmission Planners as long as Generator Owners confirm that their voltage and frequency settings comply with the performance curves in the attachments. It may be valid to require an estimate of performance if the GO identifies a limitation as allowed under R3. Otherwise, the TP should assume generator relays will operate if the magnitude and duration thresholds defined in the attachments are exceeded.
Response: Thank you for your comments. The SDT has removed Requirement R4.		

Organization	Yes or No	Question 3 Comment
Luminant Energy	No	Note: This appears to be dealing with R5 and not R4.R5 Because of the requirement under R5.3 (identification for basis for estimates of probability of staying on-line, etc), the study would take considerable time to compile. I would recommend that the generator owner be provided 90 calendar days rather that the suggested 30 to submit the results. **The SDT agrees that more time should be allowed and has changed the time to 60 days.** R5.1 It appears that a frequency and voltage excursion must occur at the same time with the estimated time duration that the unit will remain connected. Was it intended that the “and” be an “or”? **The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.** Would LVRT dovetail into relay loadability for stressed conditions for low voltage conditions between 45 and 90%? (Generator relay loadability is evaluated at 85% (PRC-023-2).) . **The SDT does not believe that this would replace an evaluation of relay loadability.** R5.3 Luminant recommends removing this requirement. . **The SDT believes this information will help the Transmission Planner determine a level of confidence in the estimate.**
Response: Thank you for your comments. See specific responses above.		
Ameren	No	Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable
Response: Thank you for your comments. The SDT agrees that this is an estimate and not deterministic. The performance of contactors is highly dependent on the phase angle of the voltage wave when the excursion occurs – which cannot be predicted. The Generator Owner may want to assume a worst case scenario.		
PPL Electric Utilities	No	1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5.2. The question above cites “frequency and voltage excursions [emphasis added],” the question 4 below deals with “frequency or voltage excursions,” para. R5.1 states “Frequency Excursion...and a Voltage Excursion” and para. R6 references “Frequency Excursion or Voltage Excursion.” The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. **The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.**

Organization	Yes or No	Question 3 Comment
		3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. **Requirement R5 in PRC-024 requires the Generator Owner to develop an estimate of the time a facility will ride through an excursion. This is significantly different than the verification of performance called for in MOD-026 or MOD-027.** 4. In the event that R5 remains as-is, a standard-specific definition of the word "plant" is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit's behavior. **The Applicability is to Generator Owners. By default, all generating units and facilities that meet the NERC Registry Criteria fall within the applicability of this standard.** 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024. **The SDT agrees that this is an estimate and not deterministic. The performance of contactors, for example, is highly dependent on the phase angle of the voltage wave when the excursion occurs – which cannot be predicted. The Generator Owner may want to assume a worst case scenario.**
Response: Thank you for your comments. See specific responses above.		
Indiana Municipal Power Agency	No	This is actually requirement R5. IMPA does not see any value in assigning a standard requirement to a Generator Owner that is just an estimation of performance when it might be a far off estimation of performance compared against actual performance of an existing unit or generating plant. This standard should concentrate on the setting of relays and not have Generator Owners estimate how their unit or generating plant will perform during a Frequency/Voltage Excursion. This standard should also not force Generator Owners to perform studies or model their unit or generating plant since they are not guaranteed or reliable either.
Response: Thank you for your comments. The SDT is charged with complying with FERC Order 693 and the recommendations in the 2003 Black Out Report to improve system modeling. If the Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner do not believe there is a reliability value in requesting the information described in Requirement R5, then they are not required to request it.		

Organization	Yes or No	Question 3 Comment
GenOn Energy	No	The comment is for R5 for the June 15, 2011 draft. The wording is too open-ended and subjective in scope. Similar to R1 & R2, the requirement should be clearly defined and limited to devices that directly respond to generator voltage or frequency. **The SDT is charged with complying with FERC Order 693 and the recommendations in the 2003 Black Out Report to improve system modeling, including the performance of the generating unit or generating facility beyond just the performance of the protection system.** R3 already requires the information of other control or protective devices. **The SDT disagrees. Requirement R3 requires information on equipment limitations (other than limitations of control or protection systems).** Typically, the Generator Owner does not monitor the interconnection voltage for protection purpose; rather generator terminal voltage is used for generator protection. The modeling is performed by others, but the burden of analysis is being placed upon the Generator Owner to determine performance probability for information not in their possession. **The SDT believes that the Generator Owner is the entity that can best develop an estimate of performance of a generating unit or generating facility as described in Requirement R5.** 30 days is a short period of time for this analysis when hit cold with a request like this, especially during outage season. **The SDT agrees that more time should be allowed and has changed the time to 60 days.**
Response: Thank you for your comments. See specific responses above.		
Imperial Irrigation District (IID)	Yes	According to the standard this language is R5
Response: Thank you for your comments. The SDT agrees.		
MRO's NERC Standards Review Forum	Yes	This question seems to be referring to R5 rather than R4.
Response: Thank you for your comments. The SDT agrees.		
Dynamics Review Subcommittee	Yes	We assume this pertains to R5 not R4. 30 days is probably not enough time for a GO to determine a suitable estimate. We recommend 90 days.
Response: Thank you for your comments. The SDT agrees that more time should be allowed and has changed the time to 60 days.		

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	Although we agree with the requirement, we noticed that the VRF and Time Horizon is missing for R4. We suggest a LOWER VRF and Long-term Planning Time Horizon.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
ISO New England Inc.	Yes	The RC/PC/TOP/TP functional entities provide for a wide-area view of the transmission system and its operating limitations. These entities need accurate generator characteristics in order to correctly plan the system and to operate it within known limits.
Response: Thank you for your comments. The SDT agrees.		
American Electric Power	Yes	A Generator Owner should only be required to report known limitations that might cause their unit to trip. As written, one could be in violation of the standard for some unknown limitation which might exist and that might only be known after an event has occurred. This question seems unrelated to R4 which states the time provided to respond to a written request for information. Rather, it seems to be related instead to R3 or R5.
Response: Thank you for your comments. The question was written to apply to Requirement R5. If the Generator Owner has activated protective functions that are set inside the "no trip zone" in PRC-024 Attachment 1 or Attachment 2 and does not know of a technical limitation to changing the settings, then they can be changed and the Generator Owner will be in compliance.		
American Electric Power	Yes	A Generator Owner should only be required to report known limitations that might cause their unit to trip. As written, one could be in violation of the standard for some unknown limitation which might exist and that might only be known after an event has occurred. This question seems unrelated to R4 which states the time provided to respond to a written request for information. Rather, it seems to be related instead to R3 or R5.
Response: Thank you for your comments. The question was written to apply to Requirement R5. If the Generator Owner has activated protective functions that are set inside the "no trip zone" in PRC-024 Attachment 1 or Attachment 2 and does not know of a technical limitation to changing the settings, then they can be changed and the Generator Owner will be in compliance.		
Public Service Enterprise Group	Yes	
NERC Staff Technical Review Team	Yes	
PacifiCorp	Yes	(R4 referenced in the question actually should refer to R5 in the standard)

Organization	Yes or No	Question 3 Comment
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Manitoba Hydro	Yes	
New York Power Authority	Yes	
Puget Sound Energy	Yes	
Austin Energy	Yes	
Xcel Energy	Yes	
South Carolina Electric and Gas	Yes	
US Army Corps of Engineers	Yes	
RFC	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
GE Energy	Yes	
American Transmission Company	Yes	

4. Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer.

Please provide along with your comment, what you believe the timeframe is needed to implement this requirement.

Summary Consideration: The question mistakenly referred to Requirement R5 due to changes to the standard made by NERC Staff after the SDT had submitted the standard. This error was observed by the stakeholders and the SDT believes the responses accurately reflect the feelings of industry to the intended question. The majority of stakeholders agreed with the proposed requirement.

Based on the response to the question, no major changes were made to Requirement R6.

Organization	Yes or No	Question 4 Comment
Occidental Chemical	Negative	4. Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. Please provide along with your comment, what you believe the timeframe is needed to implement this requirement. Yes: Comments: Ingleside Cogeneration LP assumes this question actually applies to Requirement R6. The frequency and voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view.
Response: Thank you for your comments.		
Northeast Power Coordinating Council	No	The refererence to "R5" in this question should be R6.
Response: Thank you for your comments. The SDT agrees.		
SERC Generation Sub-committee (GS)	No	This appears to refer to R6.The proposed bands would need to be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design

Organization	Yes or No	Question 4 Comment
		guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant designs and no concerns were identified. However, It is not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) have been and are normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants.It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
MRO's NERC Standards Review Forum	No	If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement.		
Electric Market Policy	No	This appears to be a design question that presumably the standard drafting team researched and quantified to provide a basis in framing the curves of Attachment 1 and Attachment 2. If this is true, more documentation

Organization	Yes or No	Question 4 Comment
		should be provided to the ballot body.
Response: Thank you for your comments. The curves of PRC-024 Attachment 1 match the curves for "Expected Generator Tripping" in PRC-006 Attachment 1 that sets expectations for UFLS system performance. There is a margin between the UFLS performance expectation and the generator tripping curves. The curves of PRC-024 Attachment 2 were developed based on the existing wind generator low voltage ride through curve in FERC Order 661-A, studies done in WECC and various European voltage ride through requirements (see the Reference cited in the Standard). All of this information is available to the ballot body.		
FirstEnergy	No	Requirement R5 - It may not be feasible for the GO to provide this information in 30 days. We suggest allowing 90 days. **The SDT agrees that more time should be allowed and has changed the time to 60 days.** Regarding 5.2 and the estimation of the probability, we are not clear as to what is required. The wording is confusing and cannot offer suggestions because we are not sure what the intent is. **The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard.** R5.1 - Some nuclear plants will not be able to run at 95% voltage indefinitely as required as that voltage is lower than each plant's Licensing Basis for degraded grid voltage. We ask that this standard include an exception for nuclear generators that allow them to report what % of grid voltage will force them into a Limiting Condition of Operation if that % voltage is higher than 95%. **The condition described would be a technical limitation and would allow the Generator Owner of that facility an exemption from that portion of the PRC-024 Attachment 2 "no trip zone" that the limitation describes.**
Response: Thank you for your comments. See specific responses above.		
Santee Cooper	No	This appears to refer to R6.The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidence provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 "American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)"as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants

Organization	Yes or No	Question 4 Comment
		designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilzed at power generation plants.It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
Florida Municipal Power Agency	No	First, FMPA believes the SDT is referring to R6 not R5. Technically, the requirement is inconsistent with the question. The requirement is to design, build and maintain to prevent tripping, it does not say “thou shall not trip”. If a generator is designed, built and maintained to specifications that should not trip, but, a generator trips anyway in a real-life event, is that a violation?
Response: Thank you for your comments. The SDT disagrees that with FMPA’s interpretation. The actual wording is “Each Generator Owner shall design, build, and maintain its new unit or new generating plant or generating Facility so that it <u>will not trip</u>… “. As written, a trip during a frequency or voltage excursion that remains within the boundaries of the “no trip zones” in PRC-024 Attachments 1 and 2 would be a violation.		
TVA - GO	No	The proposed bands would need to be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant designs and no concerns were identified. However, it is not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) have been and are normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”as follows: a. Normal Conditions: Â±5% Continuous Duration b. Emergency Conditions: Â±10% not specified Duration These Criteria are

Organization	Yes or No	Question 4 Comment
		currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
Arizona Public Service Company	No	AZPS believes this question applies to R6. There should be an implementation period for the requirement for new units to allow the plants which have been ordered already to not to have to be redesigned.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement.		
Luminant Power	No	Luminant believes it may be technically possible to design a new generating unit or facility to ride through a low voltage event even though the cost to do so may be prohibitive and impractical. However, Luminant does not believe it is reasonable or achievable to expect the Generator Owner to be able to maintain those capabilities in perpetuity due to equipment deterioration and aging over time even though proper maintenance practices were implemented.
Response: Thank you for your comments.		
Progress Energy	No	This appears to actually refer to R6. **The SDT agrees.** PE submits the comments below with the assumption that this question is directed toward R6: The ride through voltage profile in attachment 2 is not achievable for either new or existing facilities. The issue is not the relay protection but in the capability of the auxiliary equipment (such as motor contactors, coal feeders,

Organization	Yes or No	Question 4 Comment
		instrument sensors). I do not know of any motor control contactor that will hold in when voltage goes to zero. The energy that is stored in the coil holding the contactor in place is rapid returned into the system during a time of fault. While the short circuit contribution of motors and contactors may last up to .2 seconds the majority of the stored energy is returned in the first 1/5 of the decay curve. The requirements that are specified in this standard are outside the IEEE and ANSI standards associated with manufacturing equipment used in power plants, while manufacturing of equipment to specialized standards MAY be possible the cost would be extremely high and in some cases may not be possible. **Existing plants are not required to comply with Requirement R6. For the example cited regarding contactor performance, a new plant could be designed with the contactors fed from a DC source or a UPS system. European utilities must comply with ride-through standards now. The SDT agrees that this would increase the cost of a facility.**
Response: Thank you for your comments. See specific responses above.		
Westinghouse	No	a. This is for requirement 6 not requirement 5 **The SDT agrees.** b. It is uncertain that the requirements, when translated to the 6.9kV AC distribution system and below, can be achieved with the equipment installed in new generating facilities. Most motor specifications do not require demonstrated operability below 75% motor rated terminal voltage or >5% deviation in rated frequency. Additional vendor testing would be required in order to effectively demonstrate equipment design capabilities. Additionally, plant performance has not been evaluated for the entire range of frequencies in the "No Trip Zone". More analysis would have to be performed in order to verify acceptable plant operation in these frequency bands.
Response: Thank you for your comments. A 5% deviation in frequency is 3 Hz. PRC-024 Attachment 1 allows the generator to trip if the frequency reaches 57.0 Hz or 63.0 Hz. The SDT believes the comment regarding 75% voltage relates to continuous voltage level, not a fast transient.		
Southern Company	No	1) This question is for R6, not R5. **The SDT agrees.** 2) We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers. **European utilities must comply with ride-through standards now.** 3) Even if this can be achieved, it will require significant changes in the power plant industry. This will

Organization	Yes or No	Question 4 Comment
		include major changes to plant system and equipment design standards (both U.S. and International). This alone will take years to accomplish. Then, manufacturers will have to design, build, and test plant systems and equipment to meet the new requirements. It is impractical to expect a new plant that can meet both the frequency and voltage requirements to be built in less than 10 years after R6 is imposed. **The SDT has extended the implementation of Requirement R5 to six years to allow for the development of designs that meet the Requirement.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	No	There are going to be certain exceptions to new units or facilities being capable of staying on line under the listed circumstances just as there are current exemptions for existing facilities. Exceptions could be related to VFD (variable frequency drive) operation or motor operation at the plants, which would be true of both existing and new generating plants. There is also a possibility of overcurrent trips during these voltage conditions, tripping would not necessarily be limited to voltage or frequency relays. It would be difficult for Generator Owners to answer this question fully without a thorough study of how the frequency and voltage excursions will impact generation loads. Generation protective relays do not typically base their protection on transmission system voltages at the point of interconnection.
Response: Thank you for your comments.		
Manitoba Hydro	No	While the requirement is technically achievable, justification should be provided by the drafting team for the curves in Attachments 1 and 2. It is not clear why the 'no trip zone' limits are set where they are.
Response: Thank you for your comments.		
Great River Energy	No	If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Response: The SDT has extended the implementation of Requirement R5 to six years to allow for the development of designs that meet the Requirement.		
Duke Energy	No	This appears to refer to R6. **The SDT agrees.** The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency

Organization	Yes or No	Question 4 Comment
		band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second is to utilize expensive voltage regulation devices, normally not utilized at power generation plants. This standard shouldn’t dictate a solution to the situation where a generator goes offline due to low voltage on the transmission system, because in many cases the generator going offline may not be a problem for the overall transmission system. In situations where it is a problem, a collaborative effort between the Transmission Planner and the Generator Owner would be the best approach (see AREVA white paper that has been provided to the SDT).It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
US Army Corps of Engineers	No	R5 applies to existing units. This requirement seems vague and subjective - recommend clarification. Please clarify the term "less stringent" - do you mean 'in the no-trip zone' or 'outside the no-trip zone. How will the information be used and what are the implicatios if the response is not satisfactory? R6 applies to new units - I have no comments on R6.
Response: Thank you for your comments. The SDT intended “less stringent” to mean a smaller “no trip zone” due to faster fault clearing and/or		

Organization	Yes or No	Question 4 Comment
faster voltage recovery time. The information would be used to better model generator response to system disturbances.		
Luminant Energy	No	Generating units placed in service prior to this standard normally have 30+ years lifespan. During the life span, components targeted for LVRT will experience loss of life (time in use, number of operations, environment, etc) which could result in a failure of an LVRT event at the point of interconnection. Because a study may not be able to locate every component, an increase in reliability or the ability of the plant to ride through a low voltage condition could never be guaranteed above its current level. The same issue exist for new units. If the plant was designed to maintain LVRT conditions, there is no guarantee that the plant's ability to ride through low voltage conditions can be maintained during its life span.
Response: Thank you for your comments.		
Ameren	No	Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine with any reasonable accuracy where auxiliary motors would stall and trip off, or contactors drop out.
Response: Thank you for your comments. The SDT agrees that this is an estimate and not deterministic. The performance of contactors, for example, is highly dependent on the phase angle of the voltage wave when the excursion occurs – which cannot be predicted. The Generator Owner may want to assume a worst case scenario.		
American Electric Power	No	This question references R5, but we believe the team intended to reference R6. **The SDT agrees.** The requirement for new units and plants to not trip within the envelope of Attachment 1 is reasonable; the design of turbines involves some off-nominal frequency versus accumulated time criteria and Attachment 1 is being proposed in view of existing design criteria of major manufacturers. While the Standards team has proposed this in view of OEM design criteria, it would be beneficial to obtain input from the OEMs to learn what issues if any they have with this proposal and what changes and/or incremental costs could be incurred to meet the Standard for new or existing generators. **The SDT has reviewed OEM information. Modern steam and combustion turbines can all meet PRC-024 Attachment 1. Two OEM's have commented on this standard and have not objected to Attachment 1.** The design and ability of auxiliary systems to meet the requirements outlined in Attachment 1 will require review.To not trip within the envelope of the Attachment 2 Voltage Ride-through Time Duration Curves is another matter. No requirement such as this has ever been imposed on generating units in the past and we question the need for it now. The appearance of such graphs seems to have been in response to the performance of wind farms that tripped off-line by protective relays when disturbances occurred on the transmission system. The Attachment 2 VRT curve may thus be an appropriate requirement for wind turbine generators. The applicability to conventional generation, however, is questionable. Further, the curve and the

Organization	Yes or No	Question 4 Comment
		supplemental tables (curve data points) seem to be at odds with the language of R2, e.g. R2.1.1 which states for three-phase transmission system zone 1 faults with Normal Clearing, interpreted to mean as little as 3 cycles up to and not to exceed 9 cycles depending on the transmission relay practice and transmission voltage application.Specific comments on and objections to R6-Attachment 2 are as follows: (1) It is not at all clear that a conventional generating unit could maintain synchronism during POI voltage events within the envelope of Attachment 2. The standard needs to explicitly state that Attachment 2 is not a requirement to maintain synchronism (which is already covered by TPL standards). This point must be made clear within either the text of the requirement or else in a footnote, not just the comment form. (2) Should the SDT retain this requirement, it would be advisable to limit the scope of Attachment 2 in R6 to generator over- and under-voltage relay settings and any unit auxiliary equipment over- and under-voltage protection whose operation could lead to the loss of the unit. However, it is also not at all clear whether auxiliary systems could be designed to withstand voltage disturbances within the envelope of Attachment **Requirement R6, part 6.7 allows generating units to trip for an actual or impending loss of synchronism.** 2. Further complicating auxiliary systems ride-through, while such a graph may be appropriate for wind farms, it is not appropriate for conventional synchronous generators that have a substantial capability to control the voltage they are subjected to during a system disturbance (unlike most wind farms) and whose critical auxiliary systems are usually (and should be) served from the generator bus (low side of GSU) and are thus insulated to some extent from what may happen on the transmission system. A more appropriate requirement for conventional generation would be to require an automatic over-excitation limiting (OEL) function that is coordinated with over-excitation protection. However, we believe OELs are now standard equipment among excitation equipment suppliers and should not need to be required in a standard. (3) It would be impractical, if not impossible, to test or otherwise verify generator ride-through for POI voltage disturbances within the envelope of Attachment 2. In view of the above considerations, and in the interest of treating all generation types equitably, we believe a more appropriate approach to generator voltage ride-through would be deference to TPL standards for the types of transmission system disturbances where stability needs to be maintained. This has always been an acceptable criterion for conventional generation ride-through in the past. It is not stated in these terms in this proposed standard and independent review of a random sample of units could demonstrate the units may not meet this R6-Attachment 2 performance requirement though they would meet R2.1.1 and TPL standard requirements.It would be beneficial to state somewhere that any fault or other disturbance on the transmission system for which a conventional generator is expected to survive, a wind farm must also survive without tripping. (A statement such as that may be out of place in this standard and perhaps ought rather to have been included in the new TPL-001-1.) The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied. Therefore, for the purposes of the R6 performance requirement, we believe that reference to Attachment 2 should be removed. **The SDT agrees that it is not necessary to place a requirement for OEL's in a standard and has not added it to this standard. The SDT also agrees with the impracticality of verifying ride-through capability through testing and has**

Organization	Yes or No	Question 4 Comment
		not included any requirements to this effect. One of guidelines the SDT is working under is FERC's desire for ride through performance to meet the TPL standards as they expressed in Order 693. The SDT has tried to write this standard in a technology-neutral manner. The requirements apply equally to wind (and other variable energy resources) as to conventional synchronous generators.
Response: Thank you for your comments. See specific responses above.		
Indiana Municipal Power Agency	No	This is actually requirement R6. **The SDT agrees.** IMPA does not believe this technology is currently achievable for new units or generating plant/facilities on all generation producing fronts. The technology should be in place and proven on all generation fronts before such writing of standard requirements.
Response: Thank you for your comments.		
GenOn Energy	No	Applied to R6 of the June 15, 2011 draft. It does not appear that the SDT has carefully considered the possible impact of Attachment 2 on plant electrical auxiliary motors and contactors. The SDT should ask an power plant engineering company the impact on the electrical auxiliaries of an 800MW coal unit with a scrubber.
Response: Thank you for your comments. The SDT realizes that there would be a significant impact on the design of plant auxiliary systems.		
Idaho Power - Power Production		This requirement should not exist. Generator Owners are required to comply will all approved NERC and RRO standards. It is the responsibility of the Generator Owner to see that the plant is built according to specifications which should include all approved NERC Reliability standards governing power plants.
Response: Thank you for your comments. The SDT is charged with complying with FERC Order 693 and the recommendations in the 2003 Black Out Report to improve system modeling.		
Bonneville Power Administration		R5 - WECC Reliability Subcommittee discussions indicated that protection generation relay performance at the Point of Interconnection was different than if the measurement point is at the low side or high side of the step-up transformer. The NERC Standard should specify the measurement point at the high side of either the generator step up transformer, or at the high side of the collector transformer where multiple small generators are aggregated at a collector substation.Attachment 2 - BPA suggests modifying the diagram to reflect changes to Requirement R2.1.1 above, e.g. to show that allowable voltage relay trip time is greater than the normal fault clearing time if the normal clearing time is less than 9 cycles.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. The voltage curves presented in PRC-024 Attachment 2 are already described as being at the high side of the GSU or collector transformer. The SDT believes that section 2.1.2 conveys the Generator Owner is allowed to use actual fault clearing times of less than nine cycles to set voltage-affected relays if the Transmission Planner provides the site-specific expected voltage characteristics.		
Austin Energy		The curves in Attachment 1 are more restrictive than the current ERCOT Operating Guide requirements. The equipment impact of this new requirement requires additional internal review, before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
Response: Thank you for your comments.		
Pepco Holdings Incand Affiliates	Yes	Believe this question is referring to Requirement R6 not R5 as stated in the question. **The SDT agrees.** Yes, it is possible to design a new facility to operate within the requirements identified in this standard. However, it may require specification of equipment with higher than normal overvoltage capabilities. Also, significant analyses would have to be conducted on the behavior of plant control systems (exciter controls, boiler controls, etc.), as well as equipment connected to auxiliary busses (including low voltage motor contactors) to ensure that all systems are designed with appropriate ride-through capabilities. However, it is unclear how this standard would apply to the ride through capability of units connected to the BES, but whose source of auxiliary station service power is from a non-BES interconnection. Would the units also have to ride through expected voltage excursions at the point of interconnection with the station service transformer even if the station service transformer was not fed directly from the BES?
Response: Thank you for your comments. The SDT believes that a generating facility that meets the NERC Registry Criteria for size and connection voltage would have to meet this standard regardless of its source of auxiliary station service power.		
Imperial Irrigation District (IID)	Yes	According to the standard this language is R6
Response: Thank you for your comments. The SDT agrees.		
BC Hydro and Power Authority	Yes	Frequency and voltage excursions specified in this standard are reasonable and actually less stringent then certain regional or area requirements. Generating facilities designed in line with industry practices and applicable standards should be able to ride through such disturbances. Lastly, it is in GOs best interest to have a robust design for new generating facilities.
Response: Thank you for your comments.		

Organization	Yes or No	Question 4 Comment
SPP Reliability Standards Develpment Team	Yes	Question should read R6 not R5. **The SDT agrees.** We feel that as long as everyone knows about these requirements ahead of time that there shouldn't be an issue with achieving these requirements.
Response: Thank you for your comments.		
Dynamics Review Subcommittee	Yes	Requirement R6 not R5.
Response: Thank you for your comments. The SDT agrees.		
LG&E and KU Energy	Yes	: This appears to be R6, not R5 and should be achievable for new units.
Response: Thank you for your comments.		
PPL Supply	Yes	1. Excursion-estimate requirements for new units are presented in R6, not R5. Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. **The intent is to ride through a voltage excursion or a frequency excursion, not both simultaneously.** 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult. **This standard does not require demonstration by dynamic simulation.**
Response: Thank you for your comments. See specific responses above.		
American Wind Energy Association	Yes	New reliability standards should be accompanied by grandfathering provisions for existing generators and an implementation grace period of sufficient length to ensure that manufacturers have enough time to engineer their generators to comply with the standard and that generators for which purchase orders are already in the pipeline will not need to be re-designed. The grandfathering provisions and implementation grace period schedule that were included in FERC Order 661A should be sufficient to achieve those goals if they are incorporated into this standard.
Response: Thank you for your comments. These grandfathering provisions are already written into the standard. Requirement R6 specifically states that it applies to units that are designed and built after the standard goes into effect.		

Organization	Yes or No	Question 4 Comment
New York Power Authority	Yes	It is achieveable but signficant analyses must be performed. Undervoltage relay settings must be coordinated with the plant components most sensitive to system wide voltage excursions, particularly voltage drops. In some facilities, a POI voltage dip to 0.95pu would translate to a much larger drop within the local facility such that facility auxiliaries would start tripping due to the lower volatges on the facilities internal buses. The result is that even thogh the HV bus undervolatge relay is set to allow 0.95pu on the system the facility internal distribution may not be able to cope with voltage at that low a level. Nuclear power plants are particularly susceptible to low voltage conditions as unplanned tripping of a nuclear unit is to be avoided as much as possible. Nuclear units are also susceptible to overfrequency excursions as overfrequency causes motors within the plant to run at higher speeds. Nuclear reactor coolant pumps have overspeed limits due to core internals vibration limits that must be analyzed and coordiated with system overfrequency relay settings. These analyses typically take six to twelve months to complete and validate so a 12 to 18 month timeframe should be sufficient to implement the requirement.
Response: Thank you for your comments. Existing generating facilities are allowed an exemption from portions of PRC-024 Attachment 1 and Attachment 2 for documented technical limitations such as you describe in your examples. No additional analysis would be necessary. For new units that are designed and built after the standard is implemented, the SDT believes the analysis cited would be part of the plant design process.		
Puget Sound Energy	Yes	This would require detailed information from the manufacturer of a combustion turbine. The requirement appears to be entirely reasonable for hydro installations. We expect it would take two years to complete this work.
Response: Thank you for your comments. The SDT has reviewed information from various steam and combustion turbine manufacturers. Two OEM's have commented on this standard.		
Independent Electricity System Operator	Yes	First of all, we believe the SDT meant R6, not R5. **The SDT agrees.** Also see our editorial comments under Q3, above. We believe this requirement is achievable for most cases. However, provision should be given to the Generator Owners which for specific technical reasons are unable to design a generating units to comply with the requirements. As worded, R6 does not contain this provision. **The SDT does not agree that this would be workable exception.**
Response: Thank you for your comments. See specific responses above.		
Xcel Energy	Yes	It is Requirement R6 that requires new units to ride through excursions. We believe it is technically feasible to design generating units to reach a high probability of riding through these excursions. However we do not consider the additional expense necessary to meet this objective to be of value to our customers given the

Organization	Yes or No	Question 4 Comment
		infrequency of occurrence of excursions of the magnitude described in this standard. Excursions of this type have occurred on our system and some generating units have tripped due to the excursion, but it has never led to a cascading outage. In addition, we believe new plants should not be considered in violation for a trip during an excursion if the GO can identify the reason for the trip and correct the deficiency. If the standard is made mandatory, we believe that an additional five years should be allowed for new units so that the A/E firms can develop proper design criteria for plant auxiliaries and equipment OEM's to develop designs that can handle the requirements
Response: Thank you for your comments. The SDT does not agree that the Generator Owner would not be in violation even if a mitigation plan were developed to address the cause of a trip during a frequency or voltage excursion.		
ISO New England Inc.	Yes	ISO-NE has frequency data from all generators operating within the New England footprint demonstrating, with the exception of certain nuclear plants and some smaller and very old generating units, that all generators can operate to meet the under-frequency curve depicted by PRC-024 - Attachement 1, and, in fact, can and do meet our more stringent underfrequency requirements. Within the NPCC Region existing requirements for generators have been in place for many years that are more stringent than the underfrequency curve shown here. The NPCC more stringent requirements have been shown by studies to be necessary to support a viable automatic unferfrequency load shedding program. It is our position that generators within NPCC will be required to continue meeting these more stringent requirements independent of the approval of PRC-024-2. New generating units should meet all the PRC-024-2 requirements at the time of their interconnection or in-service date. No special implementation plan should be afforded these units beyond the regulatory approval date of the standard.
Response: Thank you for your comments. The SDT believes that designing new facilities to meet the PRC-024 Attachment 2 voltage ride-through requirements will be challenging and has extended implementation of this requirement to six years from the date of approval.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP assumes this question actually applies to Requirement R6. **The SDT agrees.** The frequency and voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view.
Response: Thank you for your comments.		
RFC	Yes	For R5, Part 5.1 and 5.2 - suggest adding the word "PRC-024" in front of "Attachment 2" in the last line of the respected Parts.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. The wording in this requirement has been revised.		
Tacoma Power	Yes	
GE Energy	Yes	**1.** The requirement is achievable in concept, however, there is a serious omission in the definition of the requirement. It is not clear how the magnitude of the three phase voltage is defined, for example: average of the individual phase magnitudes, magnitude of the least phase, positive sequence. Also, it should be clearly defined whether the requirement applies to the rms, 60 Hz component, or peak magnitude of the voltage. **Thank you for your comments. The SDT agrees and has changed the wording accordingly. Clarification #5 has been added to PRC-024 Attachment 2 that states "Additionally, voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum crest phase-to-ground or phase-to-phase voltage for the high voltage duration curve."**
PPL Electric Utilities	Yes	1. Excursion-estimate requirements for new units are presented in R6, not R5. **Requirement R5 contains the requirement for estimating performance during an excursion.** Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. **Events that cause severe frequency excursions frequently are accompanied by voltage excursions (though usually not of the severity described by PRC-024 Attachment 2).** 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult. **This standard does not require demonstration by dynamic simulation.**
Response: Thank you for your comments. See specific responses above.		
Public Service Enterprise Group	Yes	
NERC Staff Technical Review Team	Yes	
Westar Energy	Yes	
Tri-State Generation and Transmission, Inc.	Yes	

Organization	Yes or No	Question 4 Comment
Oncor Electric Delivery Company LLC	Yes	
Tacoma Power	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Transmission Company	Yes	

5. The voltage ride-through Tables HVRT and LVRT Duration in Attachment 2, specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Do you agree with this time duration value? If not, please provide an alternative value and supporting information in the comments.

Summary Consideration: The slight majority of stakeholders indicated that they agree with the 600 second value. A large portion of stakeholders who responded "no" indicated that they felt the 600 seconds was acceptable but had other concerns with the standard. As a result of the responses to this question the SDT did not make any changes to Attachment 2.

Organization	Yes or No	Question 5 Comment
PacifiCorp	Negative	(3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditons within 95% and 105% of rated generator terminal voltage and during the transmission system conditions define in PRC-024 Attachment 2, with the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to in PRC-024 Attachment 2. 2.1.3 Tripping a generator via If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the is acceptable in the "no trip zone" in PRC-024 Attachment 2 is acceptable. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable than setting relays to trip the generator even if operating within the "no trip zone" specified in PRC-024 Attachment 2 is acceptable.
Response: Thank you for your comments. The SDT has revised the wording in the subsections of Requirement R2 to make the intent clearer. Section 2.1.1 has been removed. Section 2.1.3 now says "Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2." Section 2.1.4 now says" If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2."		

Organization	Yes or No	Question 5 Comment
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	(3) This 90% and 110% ride through times should be longer to handle contingency periods of high voltage during light load conditions or periods where large VAr resources are lost during peak loads.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. The SDT has not changed the standard in response to this comment.		
PacifiCorp	Negative	(7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. **Interaction of other power system parameters has not been addressed. However, it should be noted that reactive requirements for generating facilities is identified in Standard VAR-001 and VAR-002, and the LGIA.** (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a “one-size fits all” standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies. **The SDT is well aware that many European generation interconnection standards and requirements (Grid Codes) that have been developed, which include different voltage ride-through requirements for synchronous and non-synchronous generators (see Reference 1). While this same approach could have been included in this standard, after much discussion the STD has decided to develop one frequency and voltage ride-through standard that is inclusive of all technologies. Such an approach is considered technology neutral.**
Response: Thank you for your comments. See specific responses above. .		
Occidental Chemical	Negative	5. The voltage ride-through Tables HVRT and LVRT Duration in Attachment 2, specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Do you agree with this time duration value? If not, please provide an alternative value and supporting information in the comments. Yes: Comments: The voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP’s view. Existing facilities that cannot meet this specification must be able to document an equipment limitation as allowed in R3.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments.		
Northeast Power Coordinating Council, Inc.	Negative	Generator frequency ride-through capability is too lenient and will may not be feasible within the NPCC footprint. Â· **Regional Entities are allowed to set requirements that are more stringent than those set in continent-wide NERC standards, In the interest of accommodating regional differences, the SDT solicited region-specific off nominal frequency requirements to be incorporated into PRC-024 Attachment 1. Curves specific to the Quebec Interconnection and to WECC have been added** The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. Â· **Special Protection Schemes (SPS) are intended to maintain transmission system reliability/security requirements following system disturbances not to subvert the requirements for voltage or frequency ride through requirements of a generator. (Note: As SPS are added, they are required to meet the requirements of PRC-015-1.) SPS requirements should not be used to avoid PRC-024-1 requirements as not every system disturbance affecting a given generator would result in initiation of the SPS.** The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **PRC-024-1 does not include any exemptions for new generating units, but rather, the standard includes clarifications relative to the application of the standard. These clarifications have been included to assure consistency in the application of the standard. In developing PRC-024-1, the SDT believes that the new standard enhances reliability principles as future generation will be required to meet requirements that many existing generation facilities do not have to meet.**
Response: Thank you for your comments. See specific responses above.		
Commonwealth of Massachusetts Department of Public Utilities	Negative	Generator frequency ride-through capacity is too lenient and will not work within the NPCC footprint. **Regional Entities are allowed to set requirements that are more stringent than those set in continent-wide NERC standards, In the interest of accommodating regional differences, the SDT solicited region-specific off nominal frequency requirements to be incorporated into PRC-024 Attachment 1. Curves specific to the Quebec Interconnection and to WECC have been added** The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT believes that Generator Owners should be allowed to base protection system settings on site-specific fault clearing conditions. This is consistent with the requirements in FERC Order 661-A.** The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is

Organization	Yes or No	Question 5 Comment
		not a good practice and could lead to a proliferation of SPS installations. **Special Protection Schemes (SPS) are intended to maintain transmission system reliability/security requirements following system disturbances not to subvert the requirements for voltage or frequency ride through requirements of a generator. (Note: As SPS are added, they are required to meet the requirements of PRC-015-1.) SPS requirements should not be used to avoid PRC-024-1 requirements as not every system disturbance affecting a given generator would result in initiation of the SPS.** The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **PRC-024-1 does not include any exemptions for new generating units, but rather, the standard includes clarifications relative to the application of the standard. These clarifications have been included to assure consistency in the application of the standard. In developing PRC-024-1, the SDT believes that the new standard enhances reliability principles as future generation will be required to meet requirements that many existing generation facilities do not have to meet.**
Response: Thank you for your comments. See specific responses above.		
	Negative	My negative vote is baseed on the following: The generator ride-through capability is not sufficient and is too lenient. **Regional Entities are allowed to set requirements that are more stringent than those set in continent-wide NERC standards,** The standard needs to specify voltage relay setting requirements that include ensuring the settings are based on the actual fault clearing times of the installed circuit breakers recognizing the clearing times of the circuit breakers that are in-service on the BES. **The wording in Requirement R2 allows settings based on actual fault clearing times and voltage recovery profile if these can be provided by the Transmission Planner. In lieu of this the Generator Owner must allow for the full "no trip zone" envelope in PRC-024 Attachment 2.** The wording in the standard appears to approve the use of an SPS rather than meeting the requirements of the standard. An SPS should only be used as a limited/short time reliability resolve. Multiple Special Protetions Systems within an Area/Region risk safe and reliable operation of the Area's/Region's BES. **Special Protection Schemes (SPS) are intended to maintain transmission system reliability/security requirements following system disturbances not to subvert the requirements for voltage or frequency ride through requirements of a generator. (Note: As SPS are added, they are required to meet the requirements of PRC-015-1.) SPS requirements should not be used to avoid PRC-024-1 requirements as not every system disturbance affecting a given generator would result in initiation of the SPS.** New generating units that interconnect with the BES must meet all requirements of the standard. Standards should no longer be written to include a list of acceptable exemptions. If the generating unit is unable to meet

Organization	Yes or No	Question 5 Comment
		each and every standard requirement, it should not be permitted to interconnect to the BES. **PRC-024-1 does not include any exemptions for new generating units, but rather, the standard includes clarifications relative to the application of the standard. These clarifications have been included to assure consistency in the application of the standard.**
Response: Thank you for your comments. See specific responses above.		
Tennessee Valley Authority	Negative	The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator. **Actual clearing time (generally less than the critical clearing time) for a zone 1 three-phase fault, not to exceed 9 cycles was selected by the SDT, as a fixed 9 cycles could exceed critical clearing times for a given generating plant. The SDT is well aware of issues relative to potential steam plant auxiliary load tripping following a disturbance. Under the requirements of this standard, new generating plants will need to be designed to mitigate auxiliary load tripping.** For frequency, the ride-thru criteria should be sufficient for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. **The SDT considered inputs from major turbine manufacturers in developing the off nominal frequency requirements. Existing generating units that cannot meet a portion of the "no trip zone" in PRC-024 Attachment 1 can receive an exemption by documenting the technical limitation per Requirement R3,** For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. **Voltage ride-through requirements defined in the standard were determined based on a three-phase zone 1 transmission fault with normal clearing (which implies normal communication and breaker operation). Breaker failure analysis relative to Figure 2 is considered beyond the scope of this standard.** Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2. **NERC Standard NUC-001-2 addresses steady state interface requirements while PRC-024-1 addresses transient conditions. Some of the wording in PRC-024-1 has been modified to address nuclear-specific regulatory issues.**
Response: Thank you for your comments. See specific responses above.		

Organization	Yes or No	Question 5 Comment
SERC Generation Sub-committee (GS)	No	Comments: The GS proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
SPP Reliability Standards Develpment Team	No	We would like to see the technical background/justification of why the timeframe of 600s was chosen. We understand seeing the reasoning to expand it from 4s, but 600s (10 Minutes) seems extremely too long for voltage recovery. From a planning perspective 15 cycles (.25seconds) is standard for voltage recovery. Holding .9 from 3s to 600s could prove difficult if full load on unit and might not be enough bandwidth before you hit a loss of field relay. If enough current is provided to the field it will cause this relay to trip instantaneously. Not sure that taking a 10% hit during this instance will work.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. When the transmission system voltage is low, generators operating in AVR will be at a lagging power factor (delivering reactive power to the system). They should be a long way from the operating characteristic of a Loss of Field relay.		
LG&E and KU Energy	No	LG&E and KU Energy agrees with the SERC Generation Subcommittee and proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
Santee Cooper	No	The LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as

Organization	Yes or No	Question 5 Comment
		referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
Public Service Enterprise Group	No	Typical OEM recommended protective relay settings for generator UV are significantly more stringent than that which is outlined in Attachment 2 of the draft standard. Intuitively, it would seem that a generator and its auxiliary connect loads having the requirements to ride out 0.7 pu voltage for a period of 2 seconds is unrealistic.
Response: Thank you for your comments. The voltage duration curves in PRC-024 Attachment 2 are set at the point of interconnection with the transmission system. The generator will experience a different voltage depending on the specific characteristics of the generator, step-up transformer, and transmission system. IEEE does not recommend activating undervoltage protection for generators. If the Generator Owner chooses to activate this protection, it must be set to allow the transmission system to clear a fault and for the voltage to recover. For new generation facilities (designed and built after PRC-024-1 is implemented) the SDT believes auxiliary systems can be designed so that they will ride through the voltage excursions described in the standard.		
PPL Supply	No	Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Response: Thank you for your comments. The SDT agrees that the curves in PRC-024 Attachment 2 extend to 1000 seconds, but the period after 600 seconds is within the normal operating band of 95 – 105%.		
TVA - GO	No	TVA proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience.)
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		

Organization	Yes or No	Question 5 Comment
Westar Energy	No	We suggest that the SDT provide the technical justification for this time duration. We do not agree with the time duration of up to 600 seconds. This time duration appears to be significantly long for voltage recovery. From a planning perspective, 15 cycles or 0.25 seconds is standard for voltage recovery. Holding 0.9 from 3 seconds to 600 seconds could be difficult if there is full load on the unit. There may not be enough bandwidth before a loss of field relay occurs. If enough current is provided to the field, it will cause the relay to trip instantaneously. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of the attachment.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. The "No Trip Zone" within the Voltage Ride-Through Time Duration Curve defines the maximum time that a voltage at a given level would be expected. When the transmission system voltage is low, generators operating in AVR will be at a lagging power factor (delivering reactive power to the system). They should be a long way from the operating characteristic of a Loss of Field relay. The SDT does not believe there will be conflicts between the pro-forma Generator Interconnection Agreement requirements and the requirements of this standard.		
Luminant Power	No	Luminant believes the settings are reasonable and achievable for relay settings only.
Response: Thank you for your comments.		
Progress Energy	No	The ride through capabilities should be within the IEEE and ANSI C84.1-2006 "American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)". Standards associated with manufacturing electrical equipment
Response: Thank you for your comments. ANSI C84.1-2006 addresses the requirements for continuously supplied voltages, while PRC-024-1 addresses transient conditions.		
Westinghouse	No	Due to the excessive duration of the +/- 10% voltage excursion, it is uncertain that many new manufactured turbine generators will be able to meet the V/HZ limits set by the manufacturers. Detailed studies would need to be performed to determine the ability of newer turbine generators to ride through these conditions.
Response: Thank you for your comments. The SDT reviewed the V/Hz limits in place for existing generating equipment and found that they were outside of the "no trip zone" boundaries set by PRC-024 Attachment 2 when evaluated at 60 Hz. The SDT recognizes that under conditions of a low frequency excursion coupled with a voltage transient, the resulting V/Hz condition experienced by the generation facility could exceed equipment limitations. The SDT considers a resulting trip to protect the equipment would not be a violation of the standard.		

Organization	Yes or No	Question 5 Comment
Southern Company	No	1) The 600 seconds for +/- 10% voltage excursion is excessive. GE has published recommended generator permissible V/Hz settings for a stairstep protective solutions of not allowing > 118% V/Hz to exist longer than 2 seconds, and not allowing > 110% V/Hz to exist longer than 45 seconds. The HVRT curve requires allowing 110% V/Hz for 10 minutes, which is much longer. **The voltage duration curves in PRC-024 Attachment 2 are defined at the point of interconnection with the transmission system. The SDT expects that when the transmission system voltage is high, a generator operating under AVR would be at a lower voltage due to operation of the AVR and the impedance of the step-up transformer.** 2) Generators need a generator side excursion curve to even see if this is feasible. **The voltage at the generator terminals is highly dependent on the characteristics of a the particular generator, its step-up transformer and the transmission system at the particular location. All industry ride-through standards define voltage excursions at the transmission level.** 3) We believe a detailed study needs to be conducted by the industry for typical power plant designs to help determine the feasibility of power plants being able to ride through these extreme voltage conditions. We believe this study will demonstrate that this will not be possible without major re-design of power plant systems and components. **As the ride-through performance requirement will be applicable only to new generation facilities designed and built following approval of the standard, many of the issues raised should not be an issues relative to compliance with PRC-024-1. The SDT believes that future generating plants designs should be able to meet the standard.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	No	In studying PRC-024 Attachment 2, PacifiCorp believes that the "high voltage duration" curve, which defines the upper edge of the no trip envelope by depicting a 1.10 pu voltage between 1 second and 600 seconds, may potentially conflict with the synchronous generator Inverse-Time V/HZ Relay with Fixed-Time Unit setting recommendations contained in IEEE Std C37-102. For example: At 110% V/Hz, the relay will trip in 291.6 seconds (within the PRC-024-1 No Trip Zone). Additionally, at 109% the setting would be at 1166.4 seconds. PacifiCorp requests that the Standards Drafting Team ("SDT") further evaluate PRC-024 Attachment 2 to determine if an adjustment to the high voltage duration curve could eliminate this potential conflict.
Response: Thank you for your comments. The voltage duration curves in PRC-024 Attachment 2 are defined at the point of interconnection with the transmission system. The SDT expects that when the transmission system voltage is high, a generator operating under AVR would be at a lower voltage due to operation of the AVR and the impedance of the step-up transformer. The SDT does not believe there will be a conflict with equipment V/Hz limits when evaluated at 60 Hz.		

Organization	Yes or No	Question 5 Comment
Duke Energy	No	The LVRT portion of the curve between 0.4 seconds and 3.0 seconds should be 0.90 voltage PU. Electrical powered devices at the plant will begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
Luminant Energy	No	The LVRT chart should only be limited by values pertaining to a system fault condition as a result of primary and backup transmission line relaying trip times (usually 0-30 cycles)
Response: Thank you for your comments. Voltage ride-through requirements defined in the standard were determined based on a three-phase zone 1 transmission fault with normal clearing (which implies normal communication and breaker operation). Breaker failure analysis relative to Figure 2 is considered beyond the scope of this standard.		
Ameren	No	This 90% and 110% ride through times should be longer to handle contingency periods of high voltage during light load conditions or periods where large VAr resources are lost during peak loads. Per our Transmission Planning department high voltages of 110% have been experienced for up to 8hrs.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed.		
American Electric Power	No	We agree that a new generating unit reasonably could be required to ride-though 90 percent or 110 percent voltage at the point of interconnection for 600 seconds at nominal frequency. However, this does not take away from the concerns expressed in response to Q4.
Response: Thank you for your comments. See the SDT response to your comments on Question 4.		
Tacoma Power	No	The required voltage and frequency settings should be determined by the interconnecting entities regional off nominal voltage and frequency plans.
Response: Thank you for your comments. The SDT agrees that the Generator Owner should set protection systems to meet regional as well as NERC requirements.		

Organization	Yes or No	Question 5 Comment
PPL Electric Utilities	No	Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Response: Thank you for your comments. The SDT agrees that the curves in PRC-024 Attachment 2 extend to 1000 seconds, but the period after 600 seconds is within the normal operating band of 95 – 105%.		
CenterPoint Energy	No	(a) CenterPoint Energy agrees with the time duration value of the 0.9 pu voltage level up to 600 seconds and believes this will coordinate with existing undervoltage load shedding systems (UVLS). However, CenterPoint Energy believes there are numerous relays presently set at 2.0 seconds and 3.0 seconds to shed load in a voltage excursion and, therefore, there is not a sufficient margin for coordination at the two second and three second low voltage points in Attachment 2. CenterPoint Energy recommends these two points in Attachment 2 be revised to 2.5 and 3.5 seconds. That is, the data points (Time / Voltage) in the LVRT DURATION table would be as follows: 0.15 / 0.000, 0.30 / 0.450, 2.50 / 0.650, 3.50 / 0.750, and 600 / 0.900.(b) In addition, CenterPoint Energy believes there is insufficient margin at 1.0 seconds for high voltage ride through due to voltage over-shoot following a zone 1 fault. To provide an adequate margin, CenterPoint Energy recommends the 1.0 second high voltage point in Attachment 2 be revised to 1.5 seconds. That is, the data points (Time / Voltage) in the HVRT DURATION table would be as follows: 0.20 / 1.200, 0.50 / 1.175, 1.50 / 1.150, and 600 / 1.100.
Response: Thank you for your comments. The SDT realizes that there may be existing relays that could trip during an excursion as defined by PRC-024 Attachment 2, but could be set differently without compromising the protected equipment. The SDT would need better technical justification to change the curves.		
GenOn Energy	No	10 minutes is a long time for some unavoidable configuration of electrical auxiliaries.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed.		
Austin Energy		The equipment impact of this new requirement requires additional internal review before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement.		

Organization	Yes or No	Question 5 Comment
Exelon	Yes	Most nuclear units will not be able to meet the time duration of "up to 600 seconds" unless they have an installed Load Tap Changer (LTC). This is due to the NRC required Degraded Voltage relay protection. The purpose of degraded voltage relaying is to protect emergency buses that feed equipment necessary for safe nuclear plant shutdown during an emergency or transient.
Response: Thank you for your comments. Existing generating units (including nuclear units) that cannot meet a portion of the "no trip zone" in PRC-024 Attachment 2 can receive an exemption by documenting the technical limitation per Requirement R3,		
ISO New England Inc.	Yes	Although the time duration is acceptable ISO-NE does not agree with the band shown. See our comments on Question 1, above.
Response: Thank you for your comments. See the SDT response to your comments on Question 1.		
Ingleside Cogeneration LP	Yes	The voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view. Existing facilities that cannot meet this specification must be able to document an equipment limitation as allowed in R3.
Response: Thank you for your comments.		
Dynamics Review Subcommittee	Yes	While we agree, a technical basis for this 600 secs. duration (and each breakpoint) would be helpful.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. The breakpoints were developed after review of FERC Order 661-A, various European grid standards, and voltage profiles from simulations done in the WECC and SERC regions.		
MRO's NERC Standards Review Forum	Yes	Do not have an alternative value to suggest.
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
BC Hydro and Power Authority	Yes	

Organization	Yes or No	Question 5 Comment
Idaho Power - Power Production	Yes	
Electric Market Policy	Yes	
NERC Staff Technical Review Team	Yes	
Arizona Public Service Company	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Puget Sound Energy	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
US Army Corps of Engineers	Yes	
RFC	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	

Organization	Yes or No	Question 5 Comment
GE Energy	Yes	
American Transmission Company	Yes	
Hydro-Quebec TransEnergie	Yes	

6. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Summary Consideration: Many of the comments provided are duplications of comments provided in response to the other five questions. There are not any new concerns raised by a large number of stakeholders.

Organization	Yes or No	Question 6 Comment
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	(6)R6.2 why are smaller generators allowed to trip 10% of their units? Is this fair to large generators? **The SDT feels that allowing 10% of small generators to trip is fair because it is similar to a large unit experiencing a run back following an event. Runbacks do not result in a compliance violation.** (7)Do all the requirements of PRC-024-1 apply to all the auxiliary systems, or just the generating unit protection systems? This needs to be made clear for compliance. If applying to all auxiliary systems, guidance will need to be provided on how to meet these standards. **Requirements R1 and R2 apply only to the generator protection system as stated in the Footnote 1. Requirement 6 applies to the performance of the entire facility, not just the generator protection system.** (8)For R2 and R6, if clearing a transmission line outlet end of line fault with zone-2 timing exceeds the requirements of Attachment #2, which should be designed for. Does transmission line relays need to be designed to provide performance of Attachment #2 for newly installed facilities? **This standard does not set requirements for the protection of the transmission system. If the voltage profile at a specific generating site exceeds the requirements of Attachment #2, then the generator(s) at that site would not be out of compliance if they tripped.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	Negative	o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate**

Organization	Yes or No	Question 6 Comment
		capacity greater than 10%. o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . **Tripping generating units is allowed to protect the equipment from damage. In the example cited, it would be considered an impending loss of synchronism.**
Response: Thank you for your comments. See specific responses above.		
MidAmerican Energy Co.	Negative	Comment: Given the number and depth of comments at the NERC webinar, it is clear the NERC standard is not clear or enforceable. This will generate the need for interpretations and Compliance Application Notices which cause further confusion and enforcement issues. Technical issues are also present. It is clear that NERC standards have not been coordinated with nuclear plant NRC standards and that conflicts will result. It seems likely that many nuclear plants will have trouble meeting the new standard and performance curves. Other power plants may not be able to upgrade the many subsystems required to ensure that a plant never trips for the PRC-024 standard given in the implementation period.
Response: Thank you for your comments. Existing plants, including those in design or construction phase when this standard goes into effect, do not have to meet Requirement R6 (the performance requirement). If there are technical limitations why their protection systems cannot be set so that they operate outside of the No Trip Zones of Attachments #1 and #2, then per Requirement R3 they must document the limitation and inform the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner of the limitation.		
Constellation Energy Commodities Group; Constellation Power Source Generation, Inc.	Negative	Constellation Energy Commodites Group believes that the 7 Requirements in this standard can be condensed into a single requirement simply stating that a generator must have frequency and voltage protection set per the curves in the attachments. However, it should be noted that even if a relay is set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the “no trip zone.” If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per this standard. An allowable tolerance needs to be including in the requirements in order to capture real world conditions.
Response: Thank you for your comments. The Drafting Team believes more than one requirement is needed, both to meet the directives of Order 693 and the Blackout Report and for clarity.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>Cowlitz County PUD</td><td>Negative</td><td>Cowlitz defers to WECC comments.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Please refer to the response to WECC.</td></tr>
<tr><td>Dominion Resources Services</td><td>Negative</td><td>Dominion submits a negative ballot for the following technical reasons: 1. Do not understand R3 bullets. How does increasing your units rating by =10% change this? The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.

2. Attachment 2 does not match the Â±5% voltage schedule per the definition of Voltage Excursion. This curve is not possible. The definition of Voltage Excursion has been removed. PRC-024 Attachment 2 defines the outer boundaries of a voltage excursion. The SDT realizes that an actual excursion will never follow these boundaries, but as long as the excursion remains inside the boundaries, the generator protection system should not operate.

3. R6 grants new generators exceptions. Where are the exceptions for existing generators? Requirement R6 only applies to new generators. Existing generators are allowed exemption from portions of R1 and R2 if they can document technical limitations to their equipment as defined in Requirement R3.

4. This standard only applies to frequency and voltage excursions within the defined limits. The attachments and requirements go outside of this bound placing much more stringent criteria on the operation of the units. These more stringent criteria may not be possible and should be removed from the standard to align with the definition of applicability. The Attachments define the boundaries of the excursions. The SDT does not understand how the requirements create more stringent criteria.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. See specific responses above.</td></tr>
<tr><td>Liberty Electric Power LLC</td><td>Negative</td><td>Due to the need for changes to the underlying standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Changes have been made to the standard.</td></tr>
<tr><td>Balancing Authority of Northern California NCR11118; Sacramento Municipal Utility District</td><td>Negative</td><td>For Requirement 5.2 what does it mean to provide an estimate of performance in 25% increments? Specifying an estimate lends itself to varying interpretations, confusion and judgments. The “estimate of performance in 25% increments” portion of the requirement has been removed. The SDT agrees that it would not improve reliability.

Please consider the unit size and applicability for Requirement 6 to coincide with the development of the BES proposed definition. The applicability for Requirement R6 is for Generator Owners. This is not affected</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		by the definition of BES. The facilities that will have to comply with Requirement R6 are only new facilities that begin design, construction, and operation after this standard goes into effect. Requirement 7 dictates that generator trip settings be provided to the RC, PC, TO and TP when any request is made, is the response for the written request necessary for all four entities or just the requesting party? **The SDT agrees that the wording in Requirement R7 was confusing and has revised the wording to clarify the intent.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	Negative	In addition to the feedback noted in the comments submitted via the NERC comment process, the NO votes submitted by PacifiCorp are accompanied with the following comments: (1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. **It is not practical to define the excursions at the generator terminals due to the differences in generator, step-up transformer, and system characteristics. Other voltage ride through standards (e.g. FERC Order 661A and various European standards) all define the voltage profile at the transmission level (where the event occurs).** (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function. R1.1.5 does not require tripping for a frequency rate of change over the stated value, but does allow that tripping even if the frequency magnitude is still within the No Trip Zone.** o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1

Organization	Yes or No	Question 6 Comment
		fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **Part 2.1.1 states "… transmission system zone 1 faults…" The SDT believes this makes it clear that it does not involve the generator or distribution system.** o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . **Tripping generating units is allowed to protect the equipment from damage. In the example cited, it would be considered an impending loss of synchronism.**
Response: Thank you for your comments. See specific responses above.		
Brazos Electric Power Cooperative, Inc.	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not clear what is being voted on. For example, the "clean" document shows that there are five parts with Requirement R1. The "redline to last posted" document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **The events studied are documented in the WECC White Paper listed in Section G, References. This is**

Organization	Yes or No	Question 6 Comment
		available on the WECC web site. The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point **The curves in Attachment 1 were developed in coordination with the PRC-006 SDT which is now approved by the NERC Board of Trustees. You will note that the Generator Protection curves in PRC-006 Attachment 1 match the curves in PRC-024 Attachment 1. A Regional Variance has been added to ensure the standard coordinates with the WECC UFLS program.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.**
Response: Thank you for your comments. See specific responses above.		
North Carolina Electric Membership Corp.	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not clear what is being voted on. For example, the "clean" document shows that there are five parts with Requirement R1. The "redline to last posted" document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS

Organization	Yes or No	Question 6 Comment
		will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator,Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the Generator Owner's best interest to be responsive. Thus, this requirement is not necessary. **The SDT agrees and has removed Requirement R4.** Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		
Old Dominion Electric Coop.	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not clear what is being voted on. For example, the "clean" document shows that there are five parts with Requirement R1. The "redline to last posted" document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We

Organization	Yes or No	Question 6 Comment
		understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **The events studied are documented in the WECC White Paper listed in Section G, References. This is available on the WECC web site.** The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point **The curves in Attachment 1 were developed in coordination with the PRC-006 SDT which is now approved by the NERC Board of Trustees. You will note that the Generator Protection curves in PRC-006 Attachment 1 match the curves in PRC-024 Attachment 1.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the Generator Owner's best interest to be responsive. Thus, this requirement is not necessary. **The SDT agrees and has removed Requirement R4.** Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		
Southwest Transmission Cooperative, Inc.; Sunflower Electric Power Corporation	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not

Organization	Yes or No	Question 6 Comment
		clear what is being voted on. For example, the “clean” document shows that there are five parts with Requirement R1. The “redline to last posted” document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **The events studied are documented in the WECC White Paper listed in Section G, References. This is available on the WECC web site.** The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point **The curves in Attachment 1 were developed in coordination with the PRC-006 SDT which is now approved by the NERC Board of Trustees. You will note that the Generator Protection curves in PRC-006 Attachment 1 match the curves in PRC-024 Attachment 1.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT’s purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the Generator Owner’s best interest to be responsive. Thus, this requirement is not necessary. **The SDT agrees and has removed Requirement R4.** Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		

Organization	Yes or No	Question 6 Comment
Nebraska Public Power District	Negative	NPPD supports the comments submitted by the Midwest Reliability Organization (MRO) NERC Standards Review Forum (NSRF).
Response: Thank you for your comment. See response to the MRO NSRF.		
Liberty Electric Power LLC	Negative	Objection to the use of the word "inclusive" with the trip points for frequency relaying.
Response: Thank you for your comment. The word has been removed and an explanatory note has been added to each of the Attachments indicating that the No Trip Zone is exclusive of the lines, so setting relays to operate on a line is acceptable.		
Omaha Public Power District	Negative	OPPD is concerned with the rate of frequency change setting requested by R1.5 and would ask the SDT for justification behind the 2.5 Hz/Sec rate of frequency change. Further, some units may not be compliant to the frequency capability and voltage ride-through time duration curves requested by this standard. These technical limitations will prevent strict compliance to the standard as written.
Response: Thank you for your comments. R1.5 allows tripping if the rate of change of frequency exceeds 2.5 Hz/sec. It does not require tripping. This allows generators to have Aurora Scenario protection, which uses frequency rate of change as part of the detection scheme. The value 2.5 Hz/sec is commonly used in this type of protection. Existing generating units that cannot meet Requirements R1 or R2 for a technical limitation are allowed an exemption from the portions of Attachments 1 and 2 that the limitation prevents them from meeting. In order to receive this exemption, they must perform the actions described in Requirement R3.		
Northeast Utilities	Negative	Opposed with comments: 1) Generator frequency ride-through capability is too lenient and will not work within the NPCC footprint. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** 2) The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing.** 3) The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip generation could lead to grid instability and cascading outages. NERC Standard PRC-015 requires an SPS to meet NERC and RRO**

Organization	Yes or No	Question 6 Comment
		criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024 requirements. 4) The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **Requirement R6 sets expectations for new generating units that are far more challenging than those for existing units. The SDT believes this requirement will increase reliability while recognizing the realities of operating generating facilities.**
Response: Thank you for your comments. See specific responses above.		
Portland General Electric Co.	Negative	Per WECC Position Paper
Response: Thank you for your comments. See response to WECC.		
SERC Reliability Corporation	Negative	Please see comments of the SERC Dynamics Review Subcommittee and the SERC Generator Subcommittee.
Response: Thank you for your comments. See response to the SERC Dynamics Review Subcommittee and the SERC Generator Subcommittee.		
ISO New England, Inc.	Negative	Please see detailed comments submitted. Of specific concern, we are voting negative due to: 1. Generator frequency ride-through capability is too lenient and will not work within the NPCC footprint. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** 2. The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing.** 3. The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip generation could lead to grid instability and cascading outages. NERC Standard PRC-015 requires an SPS to meet NERC and RRO criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024**

Organization	Yes or No	Question 6 Comment
		requirements. 4. The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **Requirement R6 sets expectations for new generating units that are far more challenging than those for existing units. The SDT believes this requirement will increase reliability while recognizing the realities of operating generating facilities.**
Response: Thank you for your comments. See specific responses above.		
Wisconsin Energy Corp.	Negative	R1.5 requires generator relaying to not trip for a rate of change of frequency of 2.5 Hz/Second. The requirement to be able to detect the rate of change of frequency is not achievable with existing equipment, and therefore should be removed. Also, the need for the information in R5 is not sufficient to make this a Requirement in this Standard. This information can be provided by informal means.
Response: Thank you for your comments. R1.5 *allows* a generator to trip within the No Trip Zone of Attachment 1 if the rate of change of frequency *exceeds* 2.5 Hz/sec. There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function.		
Florida Municipal Power Pool	Negative	R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" the output between minimum and maximum output of the generator implied?
Response: Thank you for your comments. The intent is nameplate capacity. The wording has been changed accordingly.		
Public Utility District No. 1 of Chelan County	Negative	Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC regional Variance needs to be added to this draft.
Response: Thank you for your comments. A Regional Variance has been added for WECC.		
Minnkota Power Coop. Inc.	Negative	See comments of NSRF
Response: Thank you for your comment. See response to the MRO NSRF.		

Organization	Yes or No	Question 6 Comment
National Association of Regulatory Utility Commissioners	Negative	The following issues have been identified by the NPCC and need to be resolved: Â· Generator frequency ride-through capability is too lenient and will not work within the NPCC footprint. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** Â· The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing.** Â· The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip. NERC Standard PRC-015 requires an SPS to meet NERC and RRO criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024 requirements.** Â· The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **Requirement R6 sets expectations for new generating units that are far more challenging than those for existing units. The SDT believes this requirement will increase reliability while recognizing the realities of operating generating facilities.**
Response: Thank you for your comments. See specific responses above.		
Northern Indiana Public Service Co.	Negative	The related Standard Drafting subteams held a webinar on July 29 where they fielded numerous questions; issues still need to be addressed
Response: Thank you for your comments. The wording in the standard has been revised to improve clarity and remove ambiguities.		
Luminant Energy	Negative	The standard should not be addressing loadability issues as they are being evaluated in PRC-023-2. This standard should apply to generator protective relaying and its ability to ride through fault conditions.
Response: Thank you for your comments. The voltage curves in PRC-024 Attachment 2 do not require evaluating operation at 0.85 pu voltage for an extended period of time, as does PRC-023-2. Any relays that can meet PRC-023-2 requirements, will also meet the requirement the requirement to		

Organization	Yes or No	Question 6 Comment
operate at 0.90 pu voltage for an extended period.		
Lakeland Electric	Negative	The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment".
Response: Thank you for your comments. The SDT has revised the wording to make it consistent.		
Public Utility District No. 1 of Lewis County	Negative	This is another standard that should be reserved for generators larger that 100MW. Smaller generators should be exempt from frequency standards. Our plant only has a planel board frequency meter; no relaying or recording of frequency.
Response: Thank you for your comments. Without strong technical justification for changing the applicability, the SDT must use the Registry Criteria sizes (individual units 20 MVA or greater and facilities with aggregate size of 75 MVA or greater). Footnote 1 clearly states that the Generator Owner does not have to install or activate protection. If a generating unit does not have protective functions that trip the generator for frequency excursions, then it meets Requirement R1 by default.		
PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; Public Service Electric and Gas Co.	Negative	This standard has made progress, but there are ambiguities that we addressed in our comments and which the team also addressed on its July 29 Webinar. We recommend that the standard incorporate the suggested comments and the team repost the standard for a round of comments only.
Response: Thank you for your comments. The wording in the standard has been revised to improve clarity and remove ambiguities.		
Independent Electricity System Operator	Negative	We cannot support this standard for following reasons: i. Requirement R5: We do not support the requirement to provide an estimate of the performance of the units during frequency and voltage excursions. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3 (which, by the way, should be modified as we suggest below), the TPs can apply the following relevant assumptions: a. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; b. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and

Organization	Yes or No	Question 6 Comment
		2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? **The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability.** ii. R3: Please clarify the meaning of the expression "non-protection system equipment". Does it mean "a limitation imposed by equipment other than the protection system"? **SDT: Yes** Or does it refer to generating units that are NOT equipped with frequency/voltage protective relays? **SDT: No** In the latter case, how would the GO determine that the units that are not so equipped are unable to meet the criteria in Requirement R1 or R2? In our view, units that are unable to meet these criteria are those that are equipped with frequency/voltage protective relays and whose trip settings do not meet the criteria specified in R1 and R2 for specific technical reasons that are communicated to the Transmission Planners. For units that are NOT equipped with such protective relays, the suggestion that any of them may be unable to meet the criteria in R1 and R2 could be those which in the past have tripped before the thresholds. However, unless a unit repeatedly trips under like circumstances, isolated incidences do not provide sufficient evidence to arrive at a conclusive determination. And for those units that are NOT equipped with the protective relays and have never tripped before the thresholds, there is no telling whether or not they can meet the criteria. For the above reasons, we suggest the SDT to revise the R3 to convey the requirement that the GOs shall provide the technical reasons for not meeting the R1 and R2 criteria only for those units that ARE equipped with the protective relays and ARE set at different thresholds. **If a unit does not have voltage or frequency protective relays, then by default it will not be tripped by such relays during an excursion and the GO is in compliance.** iii. We believe R4 is a sub-requirement or part of R3 since R4 mandates the GO to respond to the listed entities within 30 days of receiving a request, and that in the requirement there is no mention of "what" the response should entail. The "what" is stipulated in R3. **The SDT agrees and has removed Requirement R4.** iv. R7: We assess that this requirement duplicates with what we interpret as the intent of a good part of R3, i.e., to provide the listed entities with the settings of the frequency/voltage protective relays. Regardless of whether or not a GO is able to meet R1 and R2, it should be obligated to provide the generator protection trip settings to these other entities for modeling purpose (consistent with our comments under Q3). If a GO sets the protective relays at values that do not meet the R1 and R2 criteria, then it should be obligated to provide the technical limitations that form the basis of the deviation. This requirement thus should come after R1 and R2, and replaces the as written R3 for reasons that we mention in our comments in (1), above. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments. See specific responses above.</td></tr>
<tr><td>Seattle City Light</td><td>Negative</td><td>We suggest that Requirement 5 be rewritten to require that the Generator Owner to provide the expected design performance of relaying and the performance results from a valid dynamic simulation. Requiring "estimates" of the probability of the generators remaining online after a severe fault seems arbitrary at best. It is unlikely that there is enough empiric evidence to form a valid statistical probability, and it is unclear what useful information a probability of the relaying design actually working would provide.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The “estimate of performance in 25% increments” portion of the requirement has been removed. The SDT agrees that it would not improve reliability.</td></tr>
<tr><td>Beaches Energy Services; Lakeland Electric; City of Green Cove Springs; City of Vero Beach</td><td>Negative</td><td>What does "external to the plant" mean as used in several of the requirements (e.g., R1, R2, R6)? We assume that this would also mean beyond any radial connection (e.g., generator lead) to the plant and would suggest changing the term to something like: "caused by an event beyond the point at which the plant is radially connected to the transmission system". Your assumption is correct.

Considering R1, many generators have speed protection embedded in control systems (e.g., a GE Mark V or VI), is that included in footnote 1 to the requirement in the phrase: "multi-function protective devices or protective functions within excitation controls that directly trip or provide tripping signals to the generator based on frequency or voltage inputs"? The SDT agrees and has revised the wording in the footnote to clarify the intent.

In R2, does "voltage protective relaying" include station service protection, such as motor-contactors? The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment". The wording has been changed for consistency.

R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" the output between minimum and maximum output of the generator implied? The intent is nameplate capacity. The wording has been changed accordingly..</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. See specific responses above.</td></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>Negative</td><td>Requirements R1, R2 and R6 all should have Medium VRFs. In the long-term planning horizon, a VRF can be high if a violation “under emergency, abnormal or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation or cascading”. Requirements R1, R2 and R5 do not meet the “directly cause” condition as multiple violations of this standard would have to occur along with violations of other standards. The TPL standards already require the BES to be planned for contingencies of individual units as well Category C contingencies which will result in loss of multiple units at</td></tr>
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Organization	Yes or No	Question 6 Comment
		the same plant. Additionally, TPL-004 requires the Transmission Planner and Planning Coordinator to study multiple events such as loss of a substation which could include loss of an entire generating plant. FAC-014-2 R6 requires the Planning Coordinator to identify the subset of multiple contingencies which result in stability limits. FAC-011-2 R3.3 requires the RC to determine which of these multiple contingencies qualify for use in the operating horizon. Then, of course, TOP-004-2 R1 requires the Transmission Operator to operate within the associated SOLs and IROLs and IRO-009-1 R4 requires the Reliability Coordinator to operate with IROLs. Thus, R1, R2, and R6 VRFs should be Medium. Requirement R4 does not have a VRF assigned.
Response: Thank you for your comments. This standard assumes a contingency has already occurred on the Transmission System to cause the voltage or frequency excursion. The loss of generation during a contingency could potentially lead to cascading outages. NERC defines this as a High VRF. Requirement R4 has been removed.		
Pacific Gas and Electric Company	Negative	The language contained in the VSL/VRF matrix must match the language in the Standard. Requirements R1 and R2 of PRC-024-1 require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that it does not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, would be non-compliant.
Response: Thank you for your comments. The VSL’s have been revised to address this issue.		
PacifiCorp	Negative	(6) PacifiCorp offers one comment on the Violation Severity Limits (“VSLs”) proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs.
Response: Thank you for your comments. The VSL’s have been revised to address this issue.		
Arizona Public Service Co.	Negative	“Going from Lower VSL to Severe VSL, they are spaced 10 days apart. This is very unreasonable. They

Organization	Yes or No	Question 6 Comment
		should be spaced at least 30 to 90 days apart. The settings are used in studies for long range planning horizon and delay in information on relay setting of an individual unit is not significant to BES reliability. The drafting team should not follow generic guide lines and should use reasonability in setting these VSL levels."
Response: Thank you for your comments. The time increments are based on the NERC VSL Guidelines.		
Indiana Municipal Power Agency	Negative	IMPA does not agree with the VSLs for requirement 5 which is just an estimation of unit or plant performance. IMPA recommends lower the VSLs.
Response: Thank you for your comments. The risk factor for this requirement is "Lower". The VSL's are a measure of how severity of the violation. NERC requires that all VSL's contain a "Severe" level.		
Black Hills Corp	Negative	R1 & R2 require that frequency protective relaying & voltage protective relaying be set so that it does not trip within the criteria listed in the respective requirements "unless the GO has documented & communicated a non-protection system limitation in accordance with R3". However, the language of the binary Severe VSL for R1 & R2 only identifies failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written the applicable entity coul be compliant with the language of R1 & R2, BUT based on the language of the VSL's, would be non-compliant.
Response: Thank you for your comments. The VSL's have been revised to address this issue.		
Florida Municipal Power Pool	Negative	R4 is missing the VRF and Time Horizon - would recommend Lower and Long-term Planning.
Response: Thank you for your comments. Requirement R4 has been removed.		
Sunflower Electric Power Corporation	Negative	Requirement R4 does not have a VRF assigned. Requirements R1, R2 and R6 all should have Medium VRFs. In the long-term planning horizon, a VRF can be high if a violation "under emergency, abnormal or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation or cascading". Requirements R1, R2 and R5 do not meet the "directly cause" condition as multiple violations of this standard would have to occur along with violations of other standards. The TPL standards already require the BES to be planned for contingencies of individual units as well Category C contingencies which will result in loss of multiple units at the same plant. Additionally, TPL-004 requires the Transmission Planner and Planning Coordinator to study multiple events such as loss of a substation which could include loss of an entire generating plant. FAC-014-2 R6 requires the Planning Coordinator to identify the subset of multiple contingencies which result in stability limits. FAC-011-2 R3.3 requires the RC to determine which of these multiple contingencies qualify for use in the operating horizon. Then, of course,

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		TOP-004-2 R1 requires the Transmission Operator to operate within the associated SOLs and IROLs and IRO-009-1 R4 requires the Reliability Coordinator to operate with IROLs. Thus, R1, R2, and R6 VRFs should be Medium.
Response: Thank you for your comments. Requirement R4 has been removed. This standard assumes a contingency has already occurred on the Transmission System to cause the voltage or frequency excursion. The loss of generation during a contingency could potentially lead to cascading outages. NERC defines this as a High VRF.		
Avista Corp.;BrightSource Energy, Inc.; City of Farmington; City of Redding; Cogentrix Energy, Inc.; Colorado Springs Utilities; Idaho Power Company; Los Angeles Department of Water & Power; Pacific Gas and Electric Company; South California Edison Company; Western Electricity Coordinating Council	Negative	Requirements R1 and R2 of PRC-024-1 require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that it does not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, would be non-compliant.
Response: Thank you for your comments. The VSL’s have been revised to address this issue.		
MidAmerican Energy Co.	Negative	The standard nor VSL are ready
Response: Thank you for your comments. The standard has been revised to clarify intent and remove ambiguities.		
Independent Electricity System Operator	Negative	We do not agree with the standard as posted, for which we have casted a NO vote. We are unable to support the VRFs and VSLs for the standard/requirements that we reject, and we expect the standard to be materially revised which may result in corresponding changes to the VRFs and VSLs.
Response: Thank you for your comments. The standard has been revised to clarify intent and remove ambiguities.		
Beaches Energy Services; Lakeland Electric; City of Green Cove Springs; City of Vero Beach	Negative	R4 is missing the VRF and Time Horizon - would recommend Lower and Long-term Planning

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. Requirement R4 has been removed.		
Imperial Irrigation District (IID)	No	
Santee Cooper	No	
Westar Energy	No	
Luminant Power	No	
Westinghouse	No	
American Wind Energy Association	No	
Oncor Electric Delivery Company LLC	No	
New York Power Authority	No	
Dynegy Inc.	No	
Puget Sound Energy	No	
Austin Energy	No	
Xcel Energy	No	
South Carolina Electric and Gas	No	
Ingleside Cogeneration LP	No	
Tacoma Power	No	

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Affirmative	Manitoba Hydro is voting affirmative but justification should be provided by the drafting team for the curves in Attachments 1 and 2. It is not clear why the 'no trip zone' limits are set as they are.
Response: Thank you for your comments. The frequency curves in Attachment 1 match the generator tripping curves from PRC-006 and provide a margin for UFLS programs to operate before generator tripping occurs. The voltage profile in Attachment 2 was developed using information from FERC Order 661A and studies done in the WECC and SERC regions. The WECC White Paper on their studies is cited in the Reference Section.		
Southern Company Generation	Affirmative	R4 does not have a VRF assigned to it.
Response: Thank you for your comments. Requirement R4 has been removed.		
Texas Reliability Entity	Affirmative	The VSL for R6 refers to "Requirement 6" in connection with frequency parameters and to "Attachment 2" in connection with voltage parameters. It would be more direct and consistent to refer to "Attachment 1" in connection with frequency parameters.
Response: Thank you for your comments. The SDT agrees and has revised the VSL accordingly.		
Southwest Transmission Cooperative, Inc.	Affirmative	While we are voting affirmative for the VSLs and VRFs, conforming changes will be necessary if requirements our modified per our ballot comments.
Response: Thank you for your comments. If the Standard had passed the initial ballot, then there would not have been changes to the requirements.		
Pepco Holdings Incand Affiliates	Yes	1) The applicability section from the previous draft of this standard should be re-inserted. Although the SDT chose to remove that section since the standard is intended to apply to all generation facilities that meet Compliance Registry Criteria, adding the specific generation criteria for which this standard applies within the body of the standard provides much more clarity than having to refer to a second document to define applicability. In addition, inserting the full applicability criteria would be consistent with the way Applicable Facilities are identified in Section 4.2 of PRC-019-1. **Unless there are deviations from the Registry Criteria, NERC Staff has told the SDT to write the Applicability as currently drafted. PRC-019-1 deviates with the inclusion of synchronous condensers.** 2) Requirement R 2.1.1 should be re-worded as follows: "For three-phase faults with Normal Clearing on transmission system facilities (lines, busses, transformers, etc.) adjacent to the point of interconnection, set voltage relays to ride through expected fault clearing times, not to exceed 9 cycles." The use of the term "zone 1 faults" implies that zone 1 relaying schemes are always employed on the transmission system, which may not be the case. Pilot schemes, overcurrent schemes, differential schemes, etc. may be used instead.

Organization	Yes or No	Question 6 Comment
		Also, the unit should stay connected if a fault were to occur on an adjacent bus or transformer rather than just on lines. Also, use of the term "Zone 1 fault" in Requirement R5 needs to be similarly addressed. **Requirement R2, section 2.1.1 has been removed. Clarification #2 to PRC-024 Attachment 2 has been revised to state "The curves depicted were derived from to a three-phase transmission system zone 1 faults with Normal Clearing…"** 3) Requirement R 2.1.1 should also address ride through capability for TPL Category C contingencies (i.e. single line to ground faults with a stuck breaker, or other cause for delayed clearing) since generation units are expected to remain on line during these contingencies as well. Granted, a three phase fault would be the most severe, however a single line to ground fault with delayed clearing times could also cause unwanted unit tripping, leading to a violation of Reliability Criteria. **Although PRC-024 Attachment 2 curves were derived based on the voltage profile of normally cleared Zone 1 faults, the SDT believes they cover many other contingencies, including some, but not all, from TPL Category C. The SDT believes it is unrealistic to expect generators to be designed to accommodate all Category C contingencies at all possible generating sites.** 4) The SDT in their response to comments on Draft #1 of this standard stated that "Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings." This is fine for evaluating the response to three phase faults, or other balanced system disturbances. However, if it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with three phase faults, then it is equally as important to have them remain on-line for single line to ground faults, which are much more common. During a phase to ground fault at the point of interconnection the faulted phase voltage collapses to zero but the unfaulted phase to ground voltages could rise as high as 80% of the line to line voltage for an effectively grounded system (with a coefficient of grounding = 80%). This is well in excess of the 1.2 p.u. requirement shown in Attachment 2. Generator voltage protection relays respond to actual phase voltages not just positive sequence voltages. As such, for the unit to ride through phase to ground faults at the point of interconnection then the short time 1.2 p.u. overvoltage threshold needs to be raised above 0.8 x 1.73 = 1.38 p.u. **The SDT agrees and has added Clarification #5 to PRC-024 Attachment 2 that states: "Additionally, voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum crest phase-to-ground or phase-to-phase voltage for the high voltage duration curve".** 5) The revised language in R3 referring to "the equipment limitation expires coincident with ...." is unclear and confusing. How can the "limitation" expire merely by the generating unit continuous capacity rating being increased > 10%. The Draft #1 version of this standard uses the phrase "the Generator Owner is granted an exception for that unit meeting the portion of R1 or R2 for that limitation once it provides documentation of the equipment limitation(s)..." "This exception for the equipment limitation shall expire coincident with..." The use of the term "exception, or exemption", makes more sense and is more in line with the intent of this

Organization	Yes or No	Question 6 Comment
		section. As such, the original language from Requirement R5 from Draft #1 should be re-instated. **The SDT agrees and has restored the Draft #1 wording.** 6) Typically unit connected generator protection packages, which include frequency and voltage protective elements, are supplied by voltage transformers connected on the terminals of the generator rather than on the high side of the generator step-up (GSU) transformer. For frequency elements, the frequency at the terminals of the generator is the same as on the high side of the GSU transformer. So comparison of frequency protective element set points can be made directly with Attachment 1. However, this is not true for voltage. The generator terminal voltage could be higher, or lower, than the system voltage on the high side of the GSU transformer depending on the voltage drop across the transformer, which varies depending on the generator real power output and whether the generator is supplying or absorbing reactive power. Since this standard requires the generation to remain connected for specific voltage criteria as measured at the point of interconnection, but the voltage sensing protection is connected to the generator terminals, some technical guidance (with specific examples) must be provided to allow the Generator Owner to translate these voltage criteria to the voltages seen by the protective relays on the terminals of the generator. Otherwise an incorrect evaluation may result. It is recommended that a Technical Reference Document similar to the "Power Plant and Transmission System Protection Coordination" document developed by the NERC System Protection and Control Subcommittee be produced, or the above mentioned document revised, to provide illustrative examples of how to apply the Attachment 2 POI voltage criteria to voltage sensing protective elements connected to the terminals of the generator. **The SDT agrees that the voltage seen at the generator terminals will not be the same as at the point of interconnection where the excursion occurs. Normally, the voltage at the generator terminals will be higher during the fault due to the impedance of the Generator Step-Up transformer (typically in the neighborhood of 0.4 pu during a close-in three phase fault). The GO may conservatively evaluate protective functions with voltage inputs using the POI voltage profile with the assumption that if they ride through that profile they will ride through the voltage seen at the generator terminals. Alternatively, the GO may choose to do a dynamic simulation and evaluate based on the results of that study. There are a number of good texts available on system stability. The SDT does not feel the need to write another one.** 7) Comments on "Voltage Ride-Through Curve Clarifications" which appears on the last page of the standard:Item#1 - Suggest replacing the term "scheduled operating voltage" with "nominal operating voltage". Voltage schedules may change over time, whereas "nominal" or "rated" voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, "rated" or "nominal" voltage. **The SDT agrees that "nominal" is better than "scheduled" and has changed the wording accordingly.** Item #2 - Suggest eliminating item 2. The ride-through curve is to ensure the unit remains on line for voltage excursions up to the limits defined by Attachment 2, regardless of the cause of the voltage excursion. **The SDT agrees and has changed Clarification #2 to PRC-024 Attachment 2 to read as follows: "The curves depicted were derived from to a three-phase transmission system zone 1 faults with Normal**

Organization	Yes or No	Question 6 Comment
		Clearing not to exceed 9 cycles." Item #3 - The use of the term "cumulative voltage duration" is confusing since Attachment 2 is made up of a series of discrete allowable voltage magnitudes and durations. **The SDT intentionally used the word "cumulative" so that OEM's will know how much time their equipment has to withstand any particular voltage level. It also gives relay setting engineers the ability to evaluate settings for different voltage levels at the specified duration times.** Also, the language only mentions voltage protective relaying and not other non-protective equipment, which could cause the unit to trip. Suggest re-wording as follows: "The generator shall remain connected (i.e., "ride-through") voltage excursions caused by disturbances on the transmission system, when the voltage at the point of interconnection with the BES remains within the boundaries of these curves. **The SDT agrees and has added the words "…control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs…" to Footnote 1.** "Item #5 d - suggest removing the term "scheduled", making it read "d. Voltage is measured at the point of interconnection" **The SDT agrees and has removed part "d.".**
Response: Thank you for your comments. See specific responses above.		
Northeast Power Coordinating Council	Yes	In R3, the SDT should review that generators are not required to provide a remedial plan for an equipment limitation. For the SDT's consideration is the work done by and for the NPCC UFLS RSDT. It was recommended to retain the more conservative NPCC Frequency Capability Curve for setting generator protection as opposed to the proposed Frequency Capability Curve in PRC-024-1 for the following reasons:1. Some portions of the NPCC Region have additional stages of UFLS set at lower frequency thresholds below 58 Hz. Adopting the curve in Attachment 1 may impact the effectiveness of the UFLS program from arresting frequency decline in these depressed frequency ranges. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** 2. As the numbers of distributed generators connected to the system increase, it is expected that overall generator frequency response is expected to be reduced. The distributed generation may also not need to comply with the generation trip thresholds as they may not meet the existing thresholds applicable to Generator Owners in NERC's Statement of Compliance Registry Criteria. Adopting the proposed PRC-024-1 curve would jeopardize the survival of islands that may contain increasingly larger portions of distributed generation should the frequency decline below 58 Hz. **This Standard cannot extend applicability to distributed generation that is not within the Registry Criteria. There is a separate NERC project that is**

Organization	Yes or No	Question 6 Comment
		addressing frequency response. 3. Adopting the proposed PRC-024-1 curve reduces the probability that the UFLS program will successfully arrest declining frequency for system conditions that are not addressed in NPCC's 2006 UFLS Assessment. **The Attachment 1 curves matches the generator tripping curves in the recently-approved PRC-006 standard. These curves provide some margin beyond the UFLS performance required in PRC-006.** 4. Adopting the proposed PRC-024-1 curve would decrease the ability of an island to survive more severe conditions than those considered in the UFLS design (for example, islands with a generation deficiency greater than 25 percent). **The SDT agrees that this is possible, but feels there must be a balance between system security under extreme contingencies and destroying generating equipment by requiring operation for long periods of time at very low frequencies.**
Response: Thank you for your comments. See specific responses above.		
ACES Power Members	Yes	R3 is an unnecessary requirement. Enforcement of R1 and R2 already create a de facto requirement to document limitations. Thus, R3 creates an opportunity for double jeopardy.
Response: Thank you for your comments. The SDT disagrees that Requirements R1 and R2 create a de facto requirement to document limitations. Requirement R3 is included so that the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are aware of the documented limitation and can model the performance of the generator correctly when evaluating its performance during excursions.		
BC Hydro and Power Authority	Yes	1. R2 introduces Remedial Action Schemes (RAS) as an alternative description. We recommend keeping to Special Protection System and leaving RAS in the NERC glossary. **In one region the term "Remedial Action Scheme" is used instead of "Special Protection System". The SDT does not believe the use of the term "RAS" in this standard causes confusion.** 2. We recommend a consistent use of the terms Planning Coordinator and Planning Authority. In the Purpose of this standard, Planning Coordinators are referred to. In the NERC glossary, under Planning Coordinator it says "refer to Planning Authority". The compliance registry list includes a column for Planning Authorities. The NERC Reliability Functional Model version 5 discusses Planning Coordinators only. Is the term Planning Coordinator going to replace Planning Authority? **The NERC Functional Model does not contain a "Planning Authority". The Functional Model and this standard use "Planning Coordinator".**
Response: Thank you for your comments. See specific responses above.		
SERC Generation Sub-	Yes	During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant

Organization	Yes or No	Question 6 Comment
committee (GS)		performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: o Important Existing nuclear plant settings are inside the published no-trip bands o How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. o Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform it's function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement.For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2."The comments expressed herein represent a consensus of the views of the above named members of the SERC Generation Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Response: Thank you for your comments. There is a performance requirement only for facilities that are designed and built after this standard is approved and becomes effective. Existing plants, nuclear or otherwise, that can document technical limitations to operating in portions of the No Trip Zones defined in Attachments 1 and 2 are allowed by Requirement R3 to trip to protect the equipment as long as the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are notified so they can correctly model the generator's performance during an excursion. Nuclear plants must comply with many NERC Standards beyond NUC-001-2.		
Idaho Power - Power Production	Yes	In section 2.1.1, we believe that the "three phase transmission system zone 1 fault" should be clarified. Is the zone 1 referring to the generator relay backup zone 1 element? The zone 1 element of the interconnection station line protection relays? Shortest line? Longest line? Another zone 1? Also, the language was a little confusing, is this an if-then statement? Since the voltage ride through curve apparently applies to all conditions (both operating and various fault configuration), reference to the "three phase transmission system zone 1 fault" implies a limitation to applicability that is not intended, and the reference should be deleted. For R3, because the time horizon for this standard is long-term planning, we believe the 30 day communication requirement is not necessary. We believe 180 days is more in line with other reporting time frames with modeling related standards. We also believe that the equipment limitation expiration section is not needed. A simple statement stating that the when the limitation is no longer valid, the RC, PA, etc should be notified. For R6, we believe it is unnecessary to have different requirements for existing and new units. We do not see the need for performance requirements for new units. We believe this standard should be a relay settings

Organization	Yes or No	Question 6 Comment
		standard, with generator performance being considered in modeling standards. R7 is burdensome to both the Generator Owner and to the receiving entities, and also prone to causing confusion. The entities proposed to receive the protection settings (RC, PC, TO, TP) would face a difficult task to be able to properly interpret the relay settings sent. The Generator Owner is the proper entity to determine the relay settings to remain in compliance with the standard. In addition, the requirement to transmit the settings within 30 days of changes is burdensome and unnecessary. Draft PRC-019-1 properly address the issue of coordinating settings with machine capabilities, and PRC-001 properly addresses the issue coordinating settings with the TO.
Response: Thank you for your comments. See specific responses above.		
SPP Reliability Standards Develpment Team	Yes	Would like to see a more consistent approach to the comment forms and the standard. It seems there is room for clean up in the posted standard/comment form.
Response: Thank you for your comments. The SDT apologizes for the inconsistency between the comment form and the standard.		
MRO's NERC Standards Review Forum	Yes	It is not clear what the basis for the requirement of R3 with regard to a 10% or more increase in capacity would lead to an expiration of an equipment limitation as the change that results in the capacity increase may not be related in any way to the origin of the equipment limitation.
Response: Thank you for your comments. The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.		
Electric Market Policy	Yes	Dominion suggests the following:Section 3 should capitalize “frequency and voltage excursions”, as they are defined terms. **The definitions have been removed from the standard.** Do not understand R3 bullets. How does increasing your units rating by â‰¥10% change this? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** Attachment 2 does not match Â±5 voltage schedule per the definition of Voltage Excursion. This curve is not possible. R6 grants new generators exceptions. Where are the exceptions for existing generators?This standard only applies to frequency and voltage excursions within the defined limits. The attachments and requirements go outside of this bound placing much more stringent criteria on the operation of the units. These more stringent criteria may not be possible and should be removed from the standard to align with the definition of

Organization	Yes or No	Question 6 Comment
		applicability. The last sentence of the associated Implementation Plan is confusing. Suggest revising to read: "Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect."
Response: Thank you for your comments. See specific responses above.		
Dynamics Review Subcommittee	Yes	Under R5, Severe VSL Requirement 55 should be Requirement 5.R7 refers to generator protection trip settings as "specified" in R1 & R2. Settings are not specified in R1 & R2. We recommend using "referred to" instead of "as specified.""The comments expressed herein represent a consensus of the views of the above named members of the [insert the full name of the group] only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Response: Thank you for your comments. The SDT agrees and has revised the VSL's accordingly.		
LG&E and KU Energy	Yes	LG&E and KU Energy would prefer to have 60 calendar days on
Response: Thank you for your comments. The SDT does not understand which requirement you are referring to.		
FirstEnergy	Yes	FirstEnergy offers the following additional comments and suggestions:Requirement R3 - It is not clear how this requirement relates to the identified generator equipment limitations. Furthermore we are not clear what "continuous capacity rating" is referring to. We suggest the removal of the second bullet which states "the generator unit continuous capacity rating increases >= 10%". **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.. The wording has been changed from "continuous capacity" to "nameplate" to clarify intent.** Requirement R3 - This standard does not account for the fact that nuclear plants have equipment other than the generator that potentially will trip the unit at frequencies/ voltages outside of the limits shown in Attachments 1 and 2. Nuclear plant voltage and frequency trip points are set to ensure safety equipment will operated as specified in the plant's License. The standard needs to allow nuclear generators the ability to specify if something other than the generator protective relays dictates where a unit will trip. **The SDT believes that Requirement R3, as written, allows nuclear plants (or any others) to trip during a frequency or voltage excursion if the Generator Owner has documented these conditions. The intention of the SDT is that nuclear safety requirements do qualify as technical equipment limitations described in the requirement.** Under 6.7 (exception) - A unit or generating plant or generating Facility may trip if the protective functions

Organization	Yes or No	Question 6 Comment
		(such as out of step or loss of field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment. Maybe this section should include an exception for Volts/Hertz protection. **The SDT agrees and has made the wording more general to allow tripping to protect the equipment from damage.** General - The standard should state whether disturbances that include both frequency and voltage excursions are covered under the standard. For example, our Volts/Hertz protection trips in 45 seconds at 110%. The standard calls for a HVRT of 600 seconds at 110%. This current Volts/Hertz setting would not meet the standard. **The Clarifications to Attachment 2 state that the voltage excursions are to be evaluated at 60 Hz. In your example, the 600 seconds at 110% voltage is on the transmission system. Generators running in AVR voltage control mode behind a step-up transformer would be at a lower voltage due to the impedance of the transformer and operation of the AVR.**
Response: Thank you for your comments. See specific responses above.		
Public Service Enterprise Group	Yes	a. Per the July 29 webinar discussion, R2.1.1 needs to be rewritten for clarity. **The SDT agrees. This section has been revised to clarify intent.** b. The "exception" process in R3 and R4 is too vague as to "who" decides whether this standard applies to a generator. If a GO describes the limitations per R3 and one of the four entities listed in R4 inquires about a specific limitation, and the GO subsequently replies to that entity, is the exception confirmed? Under what circumstances a description of limitations by a GO in R3 would be challenged? Unless the exemption to this standard is made clear, the result will be confusion when the standard is approved. **The GO has the sole discretion in determining what equipment qualifies for a limitation under Requirement R3. There is no provision for a challenge. Requirement R4 has been removed.**
Response: Thank you for your comments. See specific responses above.		
PPL Supply	Yes	1. The term “continuous capacity rating” in the second bull-dot item of R3 should be replaced with “Normal Rating or Emergency Rating,” to eliminate ambiguity via use of NERC Glossary-defined terms. **The SDT has determined that “nameplate” rating is more appropriate.** 2. The term “non-protection system” in R3 should be replaced with “non-Protection System,” to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable) **The SDT agrees and has revised the wording to clarify intent.** 3. Paras. R5.1 and R5.2 suffer in terms of clarity. Suggest rewording these paragraphs to make them easier

Organization	Yes or No	Question 6 Comment
		to understand. **The SDT agrees and has revised the wording.** 4. An exception should be added for nuclear facilities that may not be able to ride through the frequency and voltage excursion outline in PRC-024 with out impact to nuclear safety systems. **Any existing facility (including nuclear) is allowed an exception to portions of the curves in Attachments 1 and 2 if they document the limitation and communicate the information described in Requirement R3.**
Response: Thank you for your comments. See specific responses above.		
Florida Municipal Power Agency	Yes	The bullets in R3 are onerous. The bullets would essentially eliminate the ability to replace like-with-like which would have an impact on spare equipment strategy and stores since existing spares in the warehouse could not be used. If spares were not available that could meet the new criteria, the GO would be forced to either keep a unit off-line or be non-compliant. FMPA suggests eliminating the bullet, or at most, institute something like a Cyber Security Technical Feasibility Exception (TFE) process. **The SDT disagrees since a like-for-like replacement would not result in a nameplate capacity increase, so the GO would be allowed to maintain its exception.** In addition, in the bullets at the end of R3, is the 10% incremental or cumulative over time? E.g., if a GO does a capacity augmentation of 5% one year and then another 5% increase 3 years later, does that trigger the 10%? **The intent is a cumulative increase. The wording has been revised to reflect the intent.** R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" between minimum and maximum output of the generator implied? **The intent is 20% of nameplate capacity. No testing or operational data would be needed to determine the value. The wording has been revised to reflect the intent.**
Response: Thank you for your comments. See specific responses above.		
NERC Staff Technical Review Team	Yes	The applicability section should be expanded to address both applicable entities and applicable facilities similar to MOD-025-2 and should apply to individual generating units >20 MVA (gross nameplate rating) and generating plants/Facilities >75 MVA (gross aggregate nameplate rating), regardless of interconnection voltage. **Unless there are deviations from the Registry Criteria, NERC Staff has told the SDT to write the Applicability as currently drafted.** The percentage of units that must be compliant in Effective Date sections 5.1.1, 5.2.1, and 5.3.1 should be based on an MVA basis similar to other standards in Project 2007-09, such that the phrase “% of its applicable units” is replaced with “% of its applicable units on an MVA basis. **The SDT does not see an advantage to using MVA basis as opposed to number of generating units. The intent of the three-year implementation plan is to allow any protective relay settings changes to be accomplished within**

Organization	Yes or No	Question 6 Comment
		normally scheduled maintenance outages. Using number of generating units allows Generator Owners a better chance to avoid having to schedule an outage specifically to implement changes required by this standard. ”The SDT should consider the implications of Requirement R1, part 1.5, which appears to preclude unit tripping when frequency rate-of-change is less than 2.5 Hz/s, even if the frequency is above 62.2 Hz or below 57.8 Hz. **The intent is to *allow* tripping within the No Trip Zone if the rate of change of frequency *exceeds* 2.5 Hz/sec. The wording has been changed to reflect the intent.** The voltage curves in Attachment 2 should be applicable for any operating condition that falls within the voltage-time curves regardless of the initiating event that causes the voltage excursion. As such, Requirement R2, part 2.1.1 should be removed from the standard. **The SDT agrees and has removed Requirement R2, part 2.1.1. In addition, it has revised PRC-024 Attachment 2, Clarification #2 to say “The curves depicted were derived from to a three-phase transmission system zone 1 faults with Normal Clearing not to exceed 9 cycles.”** Also, we understand from the webinar that the voltage curves in Attachment 2 represent positive sequence voltage. If voltage relays that sense phase-to-ground or phase-to-phase voltage are set according to this curve, generator tripping could occur for normally cleared unbalanced faults (e.g., the unfaulted phase voltage during a single-line-to-ground may exceed 1.2 per unit on an effectively grounded system). The drafting team must develop curves that can be used directly for setting protective relays to assure that generators remain connected for both balanced and unbalanced faults.System conditions may change more quickly than a Transmission Planner can identify and convey applicable voltage relay setting requirements to a Generator Owner. **The SDT has determined that “least phase voltage” for the low voltage portion of Attachment 2, and “greatest phase voltage” for the high voltage portion of Attachment 2 are more correct than “positive sequence voltage” and the wording has been changed accordingly.** We are not aware of any reason a Transmission Planner would require less stringent criteria than Attachment 2. For these reasons, the following items should be deleted:(1) Requirement R2, part 2.1.2;(2) The phrase referring to “the voltage profile at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault . . .” in Requirement R5, parts 5.1 and 5.2;(3) Requirement R6, part 6.3; and (4) Note 2 to the Voltage Ride-Through Curve Clarifications.Equipment limitations will not change based on modifications to changes in generating unit capacity. **The SDT allows the Transmission Planner to provide a voltage profile to a Generator Owner based on the actual clearing times at that site. This may be less stringent than the curves in PRC-024 Attachment 2, but may not be more stringent.** The second sentence in Requirement R3 should be changed from “the equipment limitation expires . . .” to “The waiver for compliance with Requirements R1 and R2 associated with the equipment limitations expires .

Organization	Yes or No	Question 6 Comment
		The SDT agrees and has changed the wording accordingly. ”The conditions in Requirement R6, parts 6.1 and 6.2 could be interpreted to indicate that this requirement only applies to generating plants/Facilities greater than 75 MVA. The standard should be revised to be clear that it also applies to generating units greater than 20 MVA. **The SDT intent is that these 6.2 only apply to facilities with generating units <20 MVA that aggregate to >75 MVA. 6.1 is written without size designations, although 6.1.1 is written similarly to 6.2 with the same intent.**
Response: Thank you for your comments. See specific responses above.		
Bonneville Power Administration	Yes	The proposed standard uses both "zone 1" and "Zone 1", which we assume mean the same thing. What is the source of the Zone 1 determination?
Response: Thank you for your comments. The SDT used studies of normally cleared three-phase Zone 1 transmission system faults as the basis for developing the curves in PRC-024 Attachment 2 since this provided the most severe voltage profile. The curves in Attachment 2 are similar to those developed in FERC’s Order 661-A and various international grid codes.		
TVA - GO	Yes	During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: o Important Existing nuclear plant settings are inside the published no-trip bands o How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. o Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2.
Response: Thank you for your comments. There is a performance requirement only for facilities that are designed and built after this standard is approved and becomes effective. Existing plants, nuclear or otherwise, that can document technical limitations to operating in portions of the No Trip Zones defined in Attachments 1 and 2 are allowed by Requirement R3 to trip to protect the equipment as long as the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are notified so they can correctly model the generator’s performance during an		

Organization	Yes or No	Question 6 Comment
excursion. Nuclear plants must comply with many NERC Standards beyond NUC-001-2.		
Progress Energy	Yes	Forcing the utility to delay fault clearing (a three phase bolted fault at the point of interconnection causing a zero voltage) will increase the damage to the generation facility caused by the fault. Protective relay schemes have two primary objectives, to clear a fault rapidly to minimize the impact on the Bulk Electric System and to prevent (minimize) the damage to the faulted component and the components close to the faulted component. By forcing utilities to keep a generator feeding a fault of the magnitude implied by attachment 2 of PRC-024 the regulation may increase the costs of maintaining the generator. Additional inspections after a fault may be required to assure no internal damage occurred during the event that would not be required if the generator could be isolated from the fault more rapidly.
Response: Thank you for your comments. This standard does not set any requirements for the speed of fault clearing, but does allow a generator to trip if a close-in transmission fault is not cleared within nine cycles. Good utility practice has always assumed generators will feed fault current to allow protective relaying to sense faults and operate correctly. Even if the generator trips, it will have already seen fault current so any maintenance activities the owner chooses to perform as a result of the event would occur whether it trips or rides through.		
Southern Company	Yes	1) It is recommended to rephrase R4 so that the requirement (shall statement) is first and the conditions (within x of receiving a request) is second as follows: "The Generator Owner shall provide a written response within 90 calendar days of receipt of a written inquiry from the RC, PC, TOP, or TP regarding an equipment limitation identified in accordance with Requirement R3." More response time than 90 days is needed for cases were a written inquiry is given to a GO (with a very large number of units) for all units in one request. **The SDT has removed Requirement R4.** 2) We believe that the condition specified in R6.2 should be limited to PV plants and wind farms? **The SDT has been charged to write the standard in a technology-neutral manner. If R6.2 is allowed for wind farms and PV plants and not for an hydro facility with a number of small generators it would be discriminatory.** 3) Since Requirement R6 provides exceptions to the requirement (6.3 thru 6.7) these exceptions need to be mentioned in Measure M6. (add "unless one of the exceptions 6.3-6.7 apply" to the end of the sentence.) **The Measure refers to the Requirement, which includes all sub parts.** 4) Employing new grid frequency and voltage ride-through requirements may impact the licensing and design basis of nuclear facilities. NUC-001-1 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown. This is achieved through development of Nuclear Plant Interface Requirements (NPLRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable

Organization	Yes or No	Question 6 Comment
		Transmission Entities. The NPLRs are requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance or transient condition is important. It is essential that this process be followed closely in attempting to apply new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant's licensing and design basis. It is fundamental that the safety of nuclear power plants take precedence. **While the Transmission Owner can address preventable challenges, equipment failures and weather-induced transients can still occur. Grid stability would be compromised if one type of generating facility is allowed to trip for any excursion in voltage or frequency.** 5) R3 states "each" non-protection system equipment limitation where R1 and R2 say "a". Is there a reason for this difference? The feasibility of fully analyzing an existing plant to determine this is extremely questionable. There is no doubt that the cost would be horrendous. **The SDT has revised Requirements R1 and R2 to use the word "each". The SDT disagrees that the analysis is onerous. Requirements R1 and R2 apply only to the generator protection system. If the settings for this system are such that the generator would be tripped for conditions inside the No Trip Zone of Attachments 1 and 2, then the Generator Owner can either modify the settings or document the limitation that prevents modifying the settings (e.g. LP blade resonance during low frequency operation).** 6) We suggest modifying Footnote 2 - add "being built to a completed certified standard design" to this list. If the industry is going to move forward in utilizing standard plant designs to reduce cost and expedite getting plants built, the certified design must be acknowledged. If the equipment to meet this standard can be obtained, which is doubtful, the only way to reasonably attempt to have a design that meets it is to start with these requirements as design criteria at the very beginning. To place requirements such as this on completed standard designs would destroy the use of that concept. **Footnote 2 already includes generators "under construction". This would include those "being built to a completed certified standard design". The SDT has extended the Effective Date of Requirement R5 (the performance requirement for new facilities) from three years to six years past the date of approval in order to accommodate the need to develop new designs.** 7) The approval of this standard as written will have extreme effects on the construction and operation of generating units which could also affect safety and availability. It would greatly increase the cost and schedule for building generation units and impose a huge cost on existing ones. We believe those developing this reliability standard should be sensitive to such concerns and give them consideration. Has this been done? Is it fully documented and available for review by the industry impacted by the proposal? **Wind facilities are already required to perform to similar criteria through FERC Order 661A. European utilities also have ride through requirements in place. The SDT realizes that this will impact the design of future generating facilities and increase their cost. The SDT is also charged with complying**

Organization	Yes or No	Question 6 Comment
		with FERC Order 693 and the recommendations in the 2003 Black Out Report.
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	Yes	In addition to the feedback noted above, the NO votes submitted by PacifiCorp are accompanied with the following comments: (1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **R1.5 *allows* a generator to trip within the No Trip Zone of Attachment 1 if the rate of change of frequency *exceeds* 2.5 Hz/sec. There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function.** o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **The standard refers to transmission system Zone 1 faults.** o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate**

Organization	Yes or No	Question 6 Comment
		capacity greater than 10%. o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. **Requirement R6 contained an exception for impending or actual loss of synchronism. The SDT has revised the wording to include any condition that will damage the equipment, such as the torque swings cited.** (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered:2.1 When operating under normal system operating conditons within 95% and 105% of rated generator terminal voltage and during the transmission system conditions define in PRC-024 Attachment 2, with the following clarifications for PRC-024 Attachment 2 are provided:2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time.2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to in PRC-024 Attachment 2.2.1.3 Tripping a generator via If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the is acceptable in the "no trip zone" in PRC-024 Attachment 2 is acceptable.2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable than setting relays to trip the generator even if operating within the "no trip zone" specified in PRC-024 Attachment 2 is acceptable. **The wording in Requirement R2 has been revised to clarify intent.** (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **The SDT has added a WECC-specific curve to Attachment 1 to address WECC's UFLS program.**

Organization	Yes or No	Question 6 Comment
		(5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. **Requirement R4 has been removed.** (6) PacifiCorp offers one comment on the Violation Severity Limits ("VSLs") proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements "unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3." However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs. **The SDT agrees and has revised the VSL's for Requirements R1 and R2 accordingly.** (7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. **The SDT believes specifying dynamic reactive power requirements is beyond the scope of the SAR for this project.** (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies. **The SDT has been charged to make this standard technology neutral. If PacifiCorp feels there are significant differences in how different technologies can perform, please provide detailed information to the SDT.**
Response: Thank you for your comments. See specific responses above.		
Tri-State Generation and Transmission, Inc.	Yes	The proposed WECC-0065 does not comply with the generator overfrequency curve.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. The SDT has added a WECC-specific curve to Attachment 1 to address WECC's UFLS program.		
Manitoba Hydro	Yes	Please provide justification for the curves provided in Attachments 1 and 2.
Response: Thank you for your comments.		
Exelon	Yes	Applicability section and Requirements R.1 and R.2Most nuclear power plants will not meet the requirements for frequency due to NRC required protection for Reactor Coolant Pumps and Reactor Protection System Motor Generator sets. In addition, most nuclear power plants will not meet the voltage requirements due to NRC required degraded voltage protection. Although a provision for exemption is permitted in R.3, Exelon requests that the SDT communicate with the NRC and with the FERC to ensure a conflict of dual regulation is not imposed on a nuclear generating unit without the necessary evaluation. **The SDT believes that the existence of Requirement R3 removes any conflicting dual regulation with regard to nuclear plants.** Requirement R.3 second bulletThe equipment limitation expiration should not be dependent on a capacity increase of the generating unit. An equipment limitation may be the result of NRC regulations and not the generating unit capacity. **The SDT agrees that NRC nuclear safety requirements form a valid technical limitation. Requirement R3 has been revised so that the allowance for an equipment limitation expires only if the equipment causing the limitation is being replaced or upgraded such that there is a 10% increase in generator nameplate capacity.**
Response: Thank you for your comments. See specific responses above.		
Independent Electricity System Operator	Yes	1. R3: Please clarify the meaning of the expression "non-protection system equipment". Does it mean "a limitation imposed by equipment other than the protection system"? **SDT: Yes.** Or does it refer to generating units that are NOT equipped with frequency/voltage protective relays? **SDT: No.** In the latter case, how would the GO determine that the units that are not so equipped are unable to meet the criteria in Requirement R1 or R2? In our view, units that are unable to meet these criteria are those that are equipped with frequency/voltage protective relays and whose trip settings do not meet the criteria specified in R1 and R2 for specific technical reasons that are communicated to the Transmission Planners. For units that are NOT equipped with such protective relays, the suggestion that any of them may be unable to meet the criteria in R1 and R2 could be those which in the past have tripped before the thresholds. However, unless a unit repeatedly trips under like circumstances, isolated incidences do not provide sufficient evidence to arrive at a conclusive determination. And for those units that are NOT equipped with the protective relays and have never tripped before the thresholds, there is no telling whether or not they can meet the criteria. For the above reasons, we suggest the SDT to revise the R3 to convey the requirement that the GOs shall provide the technical reasons for not meeting the R1 and R2 criteria only for those units that ARE equipped with the

Organization	Yes or No	Question 6 Comment
		protective relays and ARE set at different thresholds. **If a unit does not have voltage or frequency protective relays, then by default it will not be tripped by such relays during an excursion and the GO is in compliance.** 2. As indicated in our comments under Q3, we think R4 is a sub-requirement or part of R3 since R4 mandates the GO to respond to the listed entities within 30 days of receiving a request, and that in the requirement there is no mention of "what" the response should entail. The "what is stipulated in R3. **The SDT agrees and has removed Requirement R4.** 3. R7: We assess that this requirement duplicates with what we interpret as the intent of a good part of R3, i.e., to provide the listed entities with the settings of the frequency/voltage protective relays. Regardless of whether or not a GO is able to meet R1 and R2, it should be obligated to provide the generator protection trip settings to these other entities for modeling purpose (consistent with our comments under Q3). If a GO sets the protective relays at values that do not meet the R1 and R2 criteria, then it should be obligated to provide the technical limitations that form the basis of the deviation. This requirement thus should come after R1 and R2, and replaces the as written R3 for reasons that we mention in our comments in (1), above. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		
Wisconsin Electric	Yes	1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. **The Applicability is to Generator Owners. By default, the applicable equipment defers to the Registry Criteria which includes only equipment connected at 100 kV or above plus black start facilities regardless of connection voltage.** 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. **The SDT has increased the Effective Date for Requirement 5 (the performance requirement) from three years to six years past the date of approval. The SDT feels the effective date for the remaining Requirements can remain the same.** 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. **R1.5 allows tripping if the frequency rate of change exceeds 2.5 Hz/sec. It does not require installation of equipment that has this capability. Allowing tripping for this rate of change within the No Trip Zone is not allowed in Requirement 1, parts 1.1 through 1.4.** 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system

Organization	Yes or No	Question 6 Comment
		faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". **Requirement R2 has be revised to clarify intent.** 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". **The SDT does not feel that 30 days is unreasonable to provide documentation of a limitation (R3) or to provide trip settings information (R7). The SDT is leaving the word "written" to differentiate between a verbal request that is not normally recorded.** 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..." **The SDT believes there is not a substantial difference between the existing and proposed wording and has not made a change.**
Response: Thank you for your comments. See specific responses above.		
We Energies	Yes	1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. **The Applicability is to Generator Owners. By default, the applicable equipment defers to the Registry Criteria which includes only equipment connected at 100 kV or above plus black start facilities regardless of connection voltage.** 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. **The SDT has increased the Effective Date for Requirement 5 (the performance requirement) from three years to six years past the date of approval. The SDT feels the effective date for the remaining Requirements can remain the same.** 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. **R1.5 allows tripping if the frequency rate of change exceeds 2.5 Hz/sec. It does not require installation of equipment that has this capability. Allowing tripping for this rate of change within the No Trip Zone is not allowed in Requirement 1, parts 1.1 through 1.4.** 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". **Requirement R2 has be revised to clarify intent** 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". **The SDT does not feel**

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		that 30 days is unreasonable to provide documentation of a limitation (R3) or to provide trip settings information (R7). The SDT is leaving the word "written" to differentiate between a verbal request that is not normally recorded. 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..." **The SDT believes there is not a substantial difference between the existing and proposed wording and has not made a change.**
Response: Thank you for your comments. See specific responses above.		
We Energies	Yes	1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. **The Applicability is to Generator Owners. By default, the applicable equipment defers to the Registry Criteria which includes only equipment connected at 100 kV or above plus black start facilities regardless of connection voltage.** 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. **The SDT has increased the Effective Date for Requirement 5 (the performance requirement) from three years to six years past the date of approval. The SDT feels the effective date for the remaining Requirements can remain the same.** 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. **R1.5 allows tripping if the frequency rate of change exceeds 2.5 Hz/sec. It does not require installation of equipment that has this capability. Allowing tripping for this rate of change within the No Trip Zone is not allowed in Requirement 1, parts 1.1 through 1.4.** 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". **Requirement R2 has be revised to clarify intent.** 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". **The SDT does not feel that 30 days is unreasonable to provide documentation of a limitation (R3) or to provide trip settings information (R7). The SDT is leaving the word "written" to differentiate between a verbal request that is not normally recorded.** 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..." **The SDT believes there is not a substantial difference between the existing**

Organization	Yes or No	Question 6 Comment
		and proposed wording and has not made a change.
Response: Thank you for your comments. See specific responses above.		
Great River Energy	Yes	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it.The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the “clean” documents. Thus, it is not clear what is being voted on. For example, the “clean” document shows that there are five parts with Requirement R1. The “redline to last posted” document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		

Organization	Yes or No	Question 6 Comment
Duke Energy	Yes	During the drafting process, quite a bit of feedback was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated, using the allowed operating bands developed as a setting coordination. The concerns include: o Existing nuclear plant settings are inside the published no-trip bands o How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. o Why is a voltage ride-thru criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed?For frequency, the ride-thru criteria should be long enough in duration for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar restrictions may also apply for the high frequency requirement.For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly.Nuclear power plant interface requirements are addressed in NERC Reliability Standard NUC-001-2. PRC-024-1 should allow nuclear power plant interface requirements to be managed under NUC-001-2.(See PowerPoint and AREVA white paper provided to the SDT).
Response: Thank you for your comments. There is a performance requirement only for facilities that are designed and built after this standard is approved and becomes effective. Existing plants, nuclear or otherwise, that can document technical limitations to operating in portions of the No Trip Zones defined in Attachments 1 and 2 are allowed by Requirement R3 to trip to protect the equipment as long as the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are notified so they can correctly model the generator's performance during an excursion. Nuclear plants must comply with many NERC Standards beyond NUC-001-2.		
US Army Corps of Engineers	Yes	-R2.1.1 - 'not to exceed 9 cycles' this wording is confusing and needs to be clarified.-Suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity includ
Response: Thank you for your comments. This part has been revised to clarify intent.		
ISO New England Inc.	Yes	Comments are provided by ISO-NE on the following requirements: R2.1. This requirement specifies when operating (within the band specified) of rated terminal voltage (VT) and during the transmission system operating conditions defined in PRC-024 Attachment 2 .... ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the "Point of Interconnection-Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. as suggested in our comments on Question 1 above R2.1.1 infers that the standard is to base the voltage relay settings on actual fault clearing times. The

Organization	Yes or No	Question 6 Comment
		standard should be 9 cycles. As the system changes, clearing times may change and then problems with an existing generator who has set its relays to the actual clearing times may be an issue. Changing this requirement would also require a change in the curve shown in Attachment 2. If this comment is ignored, as an alternative ISO-NE suggests that R2.1.1 be modified to state, "For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, plus margin, not to exceed 9 cycles." This is suggested to direct the setting of relays in a manner that will prevent a relay race that could trip the generator sooner than the actual fault clearing time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing. If the voltage profile remains within the No Trip Zone, then the Generator Owner would be out of compliance if a generator trips due to operation of a voltage relay. The SDT expects that the GO will recognize this and provide some margin in the settings.** R2.1.3 appears to provide a way to get around the intent of the standard. If a generator cannot meet the requirements of the standard, they could put in an SPS to trip the generator and avoid meeting the intent of the standard. This has the potential to lead to a proliferation of SPSs. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip generation could lead to grid instability and cascading outages. NERC Standard PRC-015 requires an SPS to meet NERC and RRO criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024 requirements.** Notwithstanding the concern over R 2.1.3, R2.1.3 and R2.1.4 should be rewritten as follows: 2.1.3. If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relays to trip the generator even if [voltage is] in the "no trip zone" in PRC-024 Attachment 2 is acceptable [provided that the voltages will not enter the trip zone for criteria faults that do not initiate the SPS or RAS].2.1.4. If clearing a system fault necessitates disconnecting a generator, then setting relays to trip the generator even if operating [voltage is]within the "no trip zone" specified in PRC-024 Attachment 2 is acceptable. **The SDT believes the suggested additional wording is not necessary.** R3 is a significant concern. In the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the "No Trip Zone", there is no requirement to correct the issue. Instead, the generator must only document the limitation. This completely undermines the intent of this standard. There is no point to setting undervoltage relays to meet the curve if other equipment is still going to trip the plant. **The SDT recognizes that contactor performance can be a factor in the ability of a generating facility to ride through a voltage excursion. We believe that requiring existing facilities to rebuild their entire auxiliary system to ride through events as severe as described by Attachment 2 (which are not common occurrences) would**

Organization	Yes or No	Question 6 Comment
		divert resources that could be better used elsewhere in improving grid reliability. Over time, as existing facilities are retired, the new facilities that are built will have to be designed to meet the performance requirement of this standard. R5 appears similar to R3 in that the generator is only required to document if it trips in the "No Trip Zone", rather than correct the issue. **This Requirement is intended to improve the modeling of generator performance by giving the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner an estimate of how long a facility will remain connected following a voltage or frequency excursion defined by one of those four entities.** Exceptions in 6.1.1 and 6.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024-2 without exception. In general, R6 and sub-requirements R6.1 through R6.7 introduce a number of conditions and exceptions for new units that are unnecessary and cumbersome to monitor. Some of them represent common sense conditions, such that if they were to occur, an auditor would be able to deem the entity to be in compliance since it is not posiible to comply with the letter of the requirement. However, there are many more cases that could be listed and you will never capture all possibilities here. Overall R6.1 through R6.7 should be deleted. As the system changes, the requirements will change. The machine should be properly designed upon installation to allow the necessary flexibility in the development of the transmission system over time. **The SDT realizes that these conditions and exceptions may not be all inclusive, but believes they cover the majority of real-world cases that would justify tripping. If the conditions and exceptions were eliminated, auditors would not have guidance to realize the intent that there are some justifiable reasons for tripping.**
Response: Thank you for your comments. See specific responses above.		
Luminant Energy	Yes	Luminant still believes that the standard should be directed to generator protective relaying only.
Response: Thank you for your comments. In order to comply with FERC Directives, a performance requirement was added to Draft 2.		
Ameren	Yes	1)Comments: Requirement R1.5 is unclear. Are the relays not allowed to trip regardless of frequency if the rate of change is less than 2.5 Hz/sec. If so, the existing generator relays don't have the capability to block for this condition. It would seem undesirable to block for this condition and risk damage to generation. **R1.5 *allows* a generator to trip within the No Trip Zone of Attachment 1 if the rate of change of frequency *exceeds* 2.5 Hz/sec.** 2)R2.1.3 needs to be more specific. With multiple outlet lines, generators may only be tripped for certain lines or breaker failure conditions. Generators would only be allowed to trip in the "no trip zone" for the specific

Organization	Yes or No	Question 6 Comment
		conditions of the SPS or RAS schemes? **The SDT believes the wording is clear as written. If an SPS or RAS detects a condition that requires tripping a generator, then that tripping is allowed.** 3)R6.2 why are smaller generators allowed to trip 10% of their units? Is this fair to large generators? **The SDT feels that allowing 10% of small generators to trip is fair because it is similar to a large unit experiencing a run back following an event. Runbacks do not result in a compliance violation.** 4)Do all the requirements of PRC-024-1 apply to all the auxiliary systems, or just the generating unit protection systems? This needs to be made clear for compliance. If applying to all auxiliary systems, guidance will need to be provided on how to meet these standards. **Requirements R1 and R2 apply only to the generator protection system as stated in the Footnote 1. Requirement 6 applies to the performance of the entire facility, not just the generator protection system.** 5)For R2 and R6, if clearing a transmission line outlet end of line fault with zone-2 timing exceeds the requirements of Attachment #2, which should be designed for. Does transmission line relays need to be designed to provide performance of Attachment #2 for newly installed facilities? **This standard does not set requirements for the protection of the transmission system. If the voltage profile at a specific generating site exceeds the requirements of Attachment #2, then the generator(s) at that site would not be out of compliance if they tripped.**
Response: Thank you for your comments. See specific responses above.		
American Electric Power	Yes	The second point under R3 causes the limitation to expire with rating increases. Is a 10 percent or more rating increase a realistic scenario and common enough to justify attention? 10 percent seems arbitrary and this provision could pose a hindrance to rating increases that may supply other reliability benefits. It may be advisable to remove this point. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** We believe that R2.1.4 must not allow relay settings to trip a generator within the no-trip zone for other system events that would not disconnect the generator. **The SDT agrees and has added wording to clarify that this tripping is only acceptable if the generator must be tripped in order to clear the fault.** The phrase "generating plant or Facility" is used in R2, R3, R5 and R6, but not R1. **The SDT agrees and has changed the wording in Requirement R1 accordingly.**
Response: Thank you for your comments. See specific responses above.		
Texas Reliability Entity	Yes	In the ERCOT Interconnection (ERCOT) there are well-established generator under-frequency relay settings

Organization	Yes or No	Question 6 Comment
		(ERCOT Nodal Operating Guides 2.6.2) that are more stringent than those proposed in this standard. ERCOT also has existing low/high-voltage ride-through requirements (ERCOT Nodal Operating Guides 2.9(2)) that are less stringent than those proposed in the standard. We would prefer to include the existing ERCOT parameters in this standard to apply within the ERCOT Region, rather than having different ERCOT and NERC requirements. We suggest that the drafting team consider adding ERCOT-specific parameters in Attachments 1 and 2, matching the existing ERCOT Nodal Operating Guide requirements, in addition to the stated parameters for the other interconnections.
Response: Thank you for your comments. The SDT has added ERCOT-specific curves to Attachment 1.		
RFC	Yes	For R3, add the word “generating” in front of the word “Facility” to be consistent with other requirements. **The SDT agrees and has changed the wording accordingly.** The followoing are reccomendations related to the Violation Severity Levels:1. VSL for R1 - a. The VSL should start off with the following language to be consistent with the language within the requirement: “The Generator Owner that has frequency protective relaying activated to trip its new or existing generating unit failed to...” **The SDT agrees and has changed the wording accordingly.** b. Since there are a number of Parts associated with R1, the SDT may want to consider gradating the VSL rather than making it Binary. **The sub parts of R1 have been removed. The VSL will remain binary.** 2. VSLs for R2 - a. The VSL should start off with the following language to be consistent with the language within the requirement: “Generator Owner that has voltage protective relaying activated to trip its new or existing unit or generating plant or Facility failed to...”b. There is no reference to any of the Part numbers for R2. Suggest adding references to the Parts to the VSL or since there are a number of Parts associated with R2, the SDT may want to consider gradating the VSL rather than making it Binary. **The sub parts of Requirement R2 are conditions that allow tripping within the No Trip Zone. They do not create violation conditions. The VSL will remain binary.** 3. VSLs for R3a. Suggest not using the language “...prevents compliance with Requirement R1 or R2...” since it is not consistent with the language of the requirement. Suggest stating: “... prevents the Generator Owner from meeting the criteria in Requirement R1 or R2...” **The SDT agrees and has changed the wording accordingly.** 4. VSLs for R5a. Fix the typo in the “Severe” VSL. Change “R55” to “R5”5. **The SDT agrees and has changed the wording accordingly.** VSLs for R6a. The first VSL under the “Severe” suggest referencing “Attachment 1” rather than “Requirement 6.” This will make it consistent with the other “Severe” VSL. **The SDT agrees and has changed the**

Organization	Yes or No	Question 6 Comment
		wording accordingly. b. Suggest adding another VSL which references the GO not following the conditions and exceptions in Parts 6.1 through 6.7. As written, there is currently no reference to the Parts. **The sub parts of Requirement R6 are conditions that allow tripping within the No Trip Zone. They do not create violation conditions. The VSL will remain binary.**
Response: Thank you for your comments. See specific responses above.		
Consolidated Edison Co. of NY, Inc.	Yes	Requirement R3. - Delete the word “expires” and replace it with the words “documentation should be renewed” **The SDT has changed the wording to clarify intent.** The underlying technical justification for this standard should be supported by a white paper similar to the document available at this link (AREVA PRC-24 White Paper Clean.doc): http://xa.yimg.com/kq/groups/28536519/188315025/name/AREVA%20PRC-24%20White%20Paper%20Clean.doc **The SAR that justified drafting of this revision to PRC-024 was approved by industry in 2007.** Requirement R3, bullet 1 allows for an exemption for existing plants subject to equipment failures until “the limitation [limiting equipment] is repaired or replaced.” Similar temporary exemption language should be incorporated in R6 for new units that experience equipment failure-related limitations. **The exemption in Requirement R3 is intended for permanent conditions due to the design of existing equipment (e.g. steam turbine LP blade fatigue life at reduced operating frequencies). If a new plant experiences an equipment failure that would prevent it from riding through an excursion, the GO can request a waiver from the Reliability Coordinator, since the RC may need the generation for reliability reasons and elect to allow a unit to operate with its greater risk of tripping during an excursion** The drafting team may also wish to address a requirement for repair or replacement timeliness in both R3 and R6. **. The SDT believes that changes made for Requirement R3 will be part of a planned uprate project and the RC’s ability to deny or rescind a waiver for Requirement R6 is incentive for the GO to make repairs expeditiously.**
Response: Thank you for your comments. See specific responses above.		
GE Energy	Yes	Clause 6.1.1 allows an exception from meeting the ride through requirements for voltage support equipment that is not in service. Often such equipment is installed solely for the purpose of acheiving ride through. It is not clear that there are any NERC standards requiring that this equipment be maintained to have a minimum

Organization	Yes or No	Question 6 Comment
		level of availability. As worded, this clause could create a means by which a GO could indefinitely avoid requirements, and subsequent penalties for non-compliance.
Response: Thank you for your comments. The SDT agrees and has removed the wording regarding voltage support equipment.		
PPL Electric Utilities	Yes	1. The term "continuous capacity rating" in the second bull-dot item of R3 should be replaced with "Normal Rating or Emergency Rating," to eliminate ambiguity via use of NERC Glossary-defined terms. **The SDT has changed the wording to "nameplate rating".** 2. The term "non-protection system" in R3 should be replaced with "non-Protection System," to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable). **The SDT agrees the wording was less than optimal and has revised Requirement R3 to state, in part, "Each Generator Owner of an existing generating unit or generating plant or Facility shall document each equipment limitation (excluding generator frequency and voltage protective relay limitations)…"** 3. Paras. R5.1 and R5.2 suffer in terms of clarity from consisting of a single sentence that is over 80 words long, with not a single comma or semicolon to guide the reader. NERC standards should make use of normal technical-writing style and punctuation **The SDT agrees. Requirement R5, section 5.2 has been removed. Section 5.1 now states "An estimate of the time duration the existing unit or generating plant or generating Facility will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion and/or a voltage excursion defined by the voltage and/or frequency profile at the point of interconnection described by dynamic simulation provided by the Transmission Planner. If the Generator Owner expects the existing unit, generating plant or generating Facility will remain connected for longer than 10 minutes, then the estimate should indicate that the existing unit, generating plant or generating Facility is not expected to trip."**
Response: Thank you for your comments. See specific responses above.		
American Transmission Company	Yes	Please give consideration to the following suggestions:1. In Requirements, R1, R2, & R3 - include a footnote for the references to "non-protection system equipment" that defines or gives a few examples of this equipment to add clarity. **The SDT believes the primary limitation will be steam turbine LP blade fatigue loss of life when operating at reduced frequencies. Generator Owners are well aware of this limitation.** 2. In Requirements, R3 - add the requirement that the GO provides the expected duration of the limitation, if it is known. **The SDT believes these would normally be permanent limitations. If the Reliability**

Organization	Yes or No	Question 6 Comment
		Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner had reason to believe a limitation was not permanent, it could make an inquiry of the Generator Owner. 3. In Requirements, R5.2 - include a footnote or example of "25% estimated probability increments" to add clarity. **The SDT has removed the Requirement R5, section 5.2 (the requirement to provide 25% probability estimates).** 4. In References - include references that provide more technical justification and background for the voltage and frequency limits given in Attachment 1 and Attachment 2 **The WECC white paper cited in References provides justification for the curves in Attachment 2. The curves in Attachment 1 are identical to PRC-006 Attachment 1 Generator Tripping expectation curves and are set to provide a margin beyond the UFLS performance expectations.** .5. In Attachment 1 - add a "Return to between 59.5 Hz and 60.5 Hz frequency" text box to be consistent with the labeling in Attachment 2. **The SDT disagrees that this is necessary because with the addition of WECC-specific and Quebec-specific curves, adding another text box would add to information overload.** 6. In Attachment 1 - add the title "Curve Data Points" to the Frequency/Time table to be consistent with Attachment 2. **The SDT agrees and has changed the wording accordingly.** 7. In Attachment 2 - modify HVRT and LVRT tables (perhaps combine them into one more compact table) to be consistent with the table in Attachment 1 and fit on the same page. **The SDT agrees and has reformatted the tables for both Attachment 1 and Attachment 2.** 8. In Attachment 2, 5a - expand to "Power factor is 0.95 lagging (i.e. supplying reactive power to the system as measured at the generator terminal)" to be more definitive. **The SDT agrees and has changed the clarification to state: "Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals)".**
Response: Thank you for your comments. See specific responses above.		
Hydro-Quebec TransEnergie	Yes	The graph of voltage from the interconnexion of Quebec was reflected from the FERC order 661-A which is different from the graph from this standard. Please justify the source of the present standard.
Response: Thank you for your comments. The voltage profile in Attachment 2 was developed using the voltage profile from FERC Order 661A, the profile developed in WECC (see the WECC White Paper listed as a Reference in the Standard), and studies done in the SERC region.		
CenterPoint Energy	Yes	(a) CenterPoint Energy does not agree with limiting the applicability of Requirement 2 to just "voltage protective relaying". In effect, this would allow possible tripping of generation during off nominal voltage

Organization	Yes or No	Question 6 Comment
		excursions from several other types of relays, such as generator backup over-current and impedance. CenterPoint Energy recommends that this standard be applicable to any generator Protection System relays that operate on voltage and / or current. **The SDT agrees and has revised Footnote 1 to state, in part, "…frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs)…"** (b) In Requirement 2.1.1, the fault clearing time should be established at a fixed 9 cycles, instead of site-specific, actual clearing times. R2.1.1 should be written as: "For three-phase transmission zone 1 faults, set generator Protection System relays based on a fault clearing time of 9 cycles". **The SDT disagrees that Generator Owners should be prevented from using site-specific clearing times and voltage profiles when they can be provided by the Transmission Planner.** (c) Requirement 2.1.2 provides for location-specific criteria that are unnecessary and could have unintended consequences, as such criteria can change over time with additions and modifications of the bulk electric system. CenterPoint Energy believes NERC reliability standards should not include fill-in-the-blank, location-specific criteria and recommends R2.1.2 be deleted. **The SDT disagrees that Generator Owners should be prevented from using site-specific clearing times and voltage profiles when they can be provided by the Transmission Planner.**
Response: Thank you for your comments. See specific responses above.		
GenOn Energy	Yes	A strong disapproval of the R3 equipment limitation expiration with a generating unit rating increase of 10%. The expiration is unnecessary and is based upon an arbitrary criterion that may be totally unrelated to basis for the limitation. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** A backwards approach has been taken with the application of Attachment 2, which represents very poor performance of the transmission system for voltage recovery after a fault. This standard will have the affect of permanently defining this as acceptable transmission performance, which should not be the case. This is inequitable since it imposes the lowest common denominator of one segment of the industry and unilaterally transfers the responsibility for that performance upon another seqment (every generating unit on the continent). **The voltage profile in Attachment 2 was developed using the voltage profile from FERC Order 661A, the profile developed in WECC (see the WECC White Paper listed as a Reference in the Standard), and studies done in the SERC region. It does not represent the lowest common**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>denominator.

The Generator Verification team has developed extensive requirement for Generator Owners to provide accurate model data for system studies, but Generator Owners get no benefits in return for their effort and expense. The SDT believes the Generator Owners get the benefit of a more reliable transmission system.

Rather than imposing Attachment 2 on Generator Owners, the more correct way is to require Planning Coordinators, Transmission Operators or Transmission Planners to provide planning study results and voltage recovery profile at the generator terminals (this is where the protection and controls are applied). This will enable Generator Owners correctly apply protection settings as appropriate. Another option is to drive performance improvements on the Transmission system. Attachment 2 should be set a much higher standard of performance of the transmission system (median or higher), and require the Planning Coordinators, Transmission Operators or Transmission Planners to identify the locations where the higher standard is not attainable and provide the voltage recovery profile. Setting performance requirements for Planning Coordinators, Transmission Operators, and Transmission Planners is beyond the scope of the SAR for this project. The SDT suggests the commenter submit a SAR if he feels this would improve grid reliability.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. See specific responses above.</td></tr>
<tr><td>Arizona Public Service Company</td><td></td><td>The measurement M6 for the new plant is not clear. One does not know how long a time it would take to get a significant event. M6 should be written such that if a unit did not trip for a system event, it will be considered compliant.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The Measure requires evidence that any trips that a generating unit experienced did not occur during a frequency or voltage excursion that remained within the No Trip Zone boundaries of Attachments 1 and 2. If the generating plant did not trip during the audit period, the final sentence in the Measure allows an attestation that the generating unit did not trip to serve as evidence of compliance.</td></tr>
<tr><td>Western Electricity Coordinating Council</td><td></td><td>For the WECC variance we would need a revised Attachment 1 that also shows the WECC No Trip Zone or an additional Attachment to illustrate the WECC variance No Trip Zone. WECC also requires modified language to R1 and the parts 1.1-1.5 to reflect the WECC variance. Requirements R5 and R6 will need to be modified to identify the appropriate Attachment for the WECC variance.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. A WECC-specific pair of curves has been added to Attachment 1.</td></tr>
</table>

Additional Comments submitted by PacifiCorp – Sandra Shaffer:

In addition to the feedback submitted via the NERC comment website, the NO votes submitted by PacifiCorp are accompanied with the following comments:

(1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. **It is not practical to define the excursions at the generator terminals due to the differences in generator, step-up transformer, and system characteristics. Other voltage ride through standards (e.g. FERC Order 661A and various European standards) all define the voltage profile at the transmission level (where the event occurs).**

(2) PacifiCorp maintains several additional concerns about complying with the standard as drafted:

- R1.1.5 – PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function. R1.1.5 does not require tripping for a frequency rate of change over the stated value, but does allow that tripping even if the frequency magnitude is still within the No Trip Zone.**
- R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **Part 2.1.1 states "… transmission system zone 1 faults…" The SDT believes this makes it clear that it does not involve the generator or distribution system.**
- R3 – This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised**

Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.

- R6 – The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. **Tripping generating units is allowed to protect the equipment from damage. In the example cited, it would be considered an impending loss of synchronism.**

(3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered:

2.1 When operating under normal system operating conditions within 95% and 105% of rated generator terminal voltage ~~and during the transmission system conditions define in PRC-024 Attachment 2, with~~ the following clarifications for PRC-024 Attachment 2 are provided:

2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, ~~set voltage relays~~ transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time.

2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent ~~voltage relay settings~~ system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to ~~in~~ PRC-024 Attachment 2.

2.1.3 Tripping a generator via ~~If~~ a Special Protection System (SPS) or Remedial Action Scheme (RAS) ~~includes tripping a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the~~ is acceptable in the "no trip zone" in PRC-024 Attachment 2 ~~is acceptable~~.

2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable ~~than setting relays to trip the generator even if operating~~ within the "no trip zone" specified in PRC-024 Attachment 2 ~~is acceptable~~.

The wording in Requirement R2 has been revised to clarify intent. It now states: "Each Generator Owner that has generator voltage protective relaying Error! Bookmark not defined. **activated to trip its new or existing unit or generating plant or generating Facility shall set its protective relaying not to trip as a result of a voltage excursion**

(at the point of interconnection3) caused by an event on the transmission system external to the plant per the following operating conditions and relay settings unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing unit or generating plant or generating Facility.

2.1 When operating within 95% to 105% of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1 **If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2.**

2.1.2 Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2.

2.1.3 **If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2."**

(4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **The SDT has added a WECC-specific curve to Attachment 1 to address WECC's UFLS program.**

(5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. **The SDT agrees and has removed Requirement R4.**

(6) PacifiCorp offers one comment on the Violation Severity Limits ("VSLs") proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements "unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3." However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

would be non-compliant. The SDT should add this critical clarification to the VSLs. **The VSL's have been revised to address this issue.**

(7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. **The SDT believes that creating dynamic reactive power requirements is beyond the scope of the SAR that was created for this project.**

(8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies. **The SDT has been charged to make this standard technology neutral. If PacifiCorp feels there are significant differences in how different technologies can perform, please provide detailed information to the SDT.**

Response: Thank you for your comments. See specific responses above.

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. First Draft of MOD-024-2 was posted for comment January 18 – February 18, 2010. MOD-024-2 was later combined with MOD-025-1 to form MOD-025-2.

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed revision to this standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This first posting is for a 30-day comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post first draft revision of standard.	April-May 2011
2. Post response to comments and second version draft revision of standard.	July – August 2011
3. Post response to comments and request authorization to ballot the revised standard.	September - October 2011
4. Conduct initial ballot.	November 2011
5. Post response to comments.	December 2011
6. Conduct recirculation ballot.	January 2012
7. BOT adoption.	February 2012
8. File with regulatory authorities.	March 2012

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

   4.1. Functional entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner

   4.2. Facilities:

   4.2.1 Individual generating unit or synchronous condenser > 20 MVA (gross nameplate rating) in a generating Facility connected at the point of interconnection at 100 kV or above.

   4.2.2 Generating plant/Facility > 75 MVA (gross aggregate nameplate rating) and connected at the point of interconnection at 100 kV or above.

   4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20% of its applicable units.

   5.1.2 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40% of its applicable units.

   5.1.3 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60% of its applicable units.

   5.1.4 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80% of its applicable units.

   5.1.5 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units.

   5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20% of its applicable units.

5.2.2 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40% of its applicable units.

5.2.3 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60% of its applicable units.

5.2.4 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80% of its applicable units.

5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units.

B. Requirements

R1. Each Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1 –.

1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2);

1.3. Submit within 90 calendar days of the date the data is recorded to its Transmission Planner.

R2. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1 ;

2.2. Record the information on Attachment 2 (or on the Transmission Owner's form that contains the same information as Attachment 2)

2.3. Submit within 90 calendar days of the verification to its Transmission Planner.

C. Measures

M1. Each Generator Owner has evidence that it performed the verification, such as a completed MOD-025 Attachment 2 or Generator Owner form with equivalent information, and has evidence that it submitted the information, such as dated electronic mail messages or mail receipts, in accordance with Requirement R1.

M2. Each Transmission Owner has evidence that it performed the verification, such as a completed MOD-025 Attachment 2 or Transmission Owner form with equivalent information, and has evidence that it submitted the information, such as dated electronic mail messages or mail receipts, in accordance with Requirement R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The Generator Owner and Transmission Owner shall each keep the latest data or evidence to show compliance as identified below, and the previous set of evidence if updated since the last compliance audit unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirement 1, Measure 1.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement 2, Measure 2.

If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real and Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days but within 100 calendar days from the date the data was recorded.	The Generator Owner verified and recorded the Real and Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 100 calendar days but within 110 calendar days from the date the data was recorded.	The Generator Owner verified and recorded the Real and Reactive Power capability of its applicable generating unit or applicable synchronous condenser but submitted the data to its Transmission Planner more than 110 calendar days but within 120 calendar days of the date the data was recorded.	The Generator Owner verified and recorded the Real and Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded. OR The Generator Owner failed to verify the Real and Reactive Power capability of an applicable generating unit. OR The Generator Owner failed to verify the Reactive Power capability of an applicable synchronous condenser unit.

				OR The Generator Owner failed to submit its verified Real or Reactive Power capability for an applicable generating unit or an applicable synchronous condenser unit to its Transmission Planner.
R2	The Transmission Owner verified and recorded the Reactive Power capability of its applicable applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days but within 100 calendar days from the date the data was recorded.	The Transmission Owner verified and recorded the Reactive Power capability of its applicable applicable synchronous condenser, but submitted the data to its Transmission Planner more than 100 calendar days but within 110 calendar days from the date the data was recorded.	The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit but submitted the data to its Transmission Planner more than 110 calendar days but within 120 calendar days of the date the data was recorded.	The Transmission Owner failed to verify the Reactive Power capability of an applicable synchronous condenser unit. OR The Transmission Owner failed to submit its verified Reactive Power capability for an applicable synchronous condenser unit to its Transmission Planner.

E. **Regional Variances**

None

F. **Associated Documents**

Version History

Version	Date	Action	Change Tracking
Version 1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability

1. For units of less than 20 MVA that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit greater than 20 MVA (gross nameplate rating).

2. Perform verification with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification, and the automatic voltage regulator in service for the Reactive Power capability verification. Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:

2.1. Perform verification of Real and Reactive Power capability of all generating units at maximum over-excited (lagging) and under-excited (leading) reactive capability at rated gross Real Power capability[1]. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of reactive capability of wind turbines and photovoltaic inverters with ninety percent of the wind turbines or photovoltaic inverters at a site on line. Maintain as steady as possible Real and Reactive Power output during verification.

2.2. Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. Conduct the rated Real Power and overexcited Reactive Power verifications required in 2.1 for a minimum of one continuous hour.

2.4. Record the under-excited reactive capability verification data required in 2.1 and 2.2 and the over-excited reactive capability verification data required in 2.2 as soon as a limit is reached.

2.5. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

3. Record the following data for the verification specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator.

[1] The generating unit's normal expected maximum Real Power at the time of the verification.

3.3. The voltage at the high and low side of the generator step-up and/or system interconnection transformer(s) at the end of the verification period.

3.4. The ambient air temperature at the end of the verification period and a correction factor, if any, to allow the Transmission Owner to correct the Real Power rating to a different ambient temperature if needed.

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing generator step-up and/or system interconnection transformer(s) tap setting.

4. Develop a simplified key one-line diagram (refer to MOD-025 Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include generator step-up and/or system interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific reactive auxiliary load(s), provide an engineering estimate and associated calculations.

5. The periodicity for performing Real and Reactive Power generating capability verification is as follows:

5.1. For staged verification; verify each generator and/or synchronous condenser or plant/facility at least every five years, (with no more than 66 calendar months between verifications), or within one year of the discovery of a change that is expected to affect its Real Power or Reactive Power capability by more than 10% of the last reported verified capability and is expected to last more than six months.

5.2. For verification using operational data; verify each generator and/or synchronous condenser or plant/facility at least every five years, within 66 calendar months between verifications, or within one year following the discovery of a change that is expected to affect its Real Power or Reactive Power capability by more than 10% of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, the Generator Owner shall designate one of the dates as the verification date, and report that date as the verification date on MOD-025- Attachment 2 for periodicity purposes.

5.3. For either verification method, new units shall be verified within one year of their commercial operation date.

Note 1: The data points obtained by the MVAR verification required by the standard may not duplicate the manufacturer supplied thermal capability curve (D-curve) due to transmission system conditions. However, the verification required by the standard may be able to uncover unit limitations such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc. which could be further analyzed for resolution. For any verification limited by transmission system conditions, the verified MVAR value obtained most likely will not be the value entered into the

Transmission Planner's database; nor is it likely this value will agree with data required to be submitted by the MOD-010 standard.

Note 2: While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system conditions. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.

MOD-025 Attachment 2

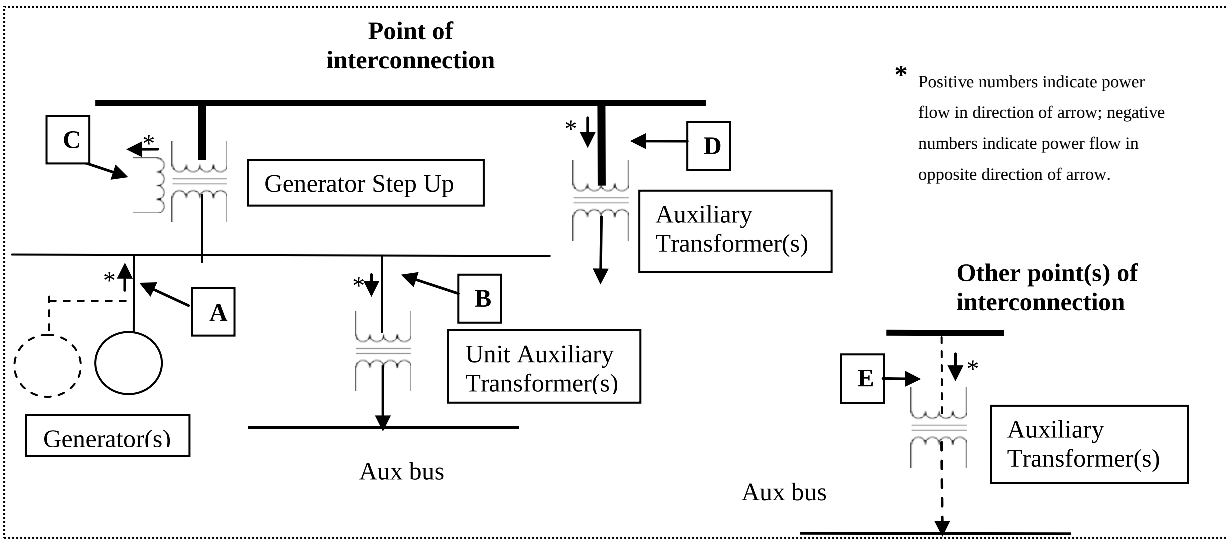
One-line Diagram, Table and Summary for Verification Information Reporting

Note: If the configuration of the generation facility does not lend itself to the use of the diagram, tables or summaries for reporting the required information, changes may be made to this form provided that all required information (identified in MOD-025 Attachement 1) is reported.

Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

Simplified one-line diagram showing plant auxiliary load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**MVAR**	Sum multiple Generators that are verified together or are part of the same unit.
Identify values that are calculated if any:				
B	**kV**	**MW**	**MVAR**	Sum multiple Unit Auxiliary Transformers.
Identify values that are calculated if any:				
C	**kV**	**MW**	**MVAR**	Sum multiple tertiary load, if any.
Identify values that are calculated if any:				
D	**kV**	**MW**	**MVAR**	Sum multiple Auxiliary Transformers.
Identify values that are calculated if any:				
E	**kV**	**MW**	**MVAR**	If multiple points of interconnection describe these for accurate modeling; report points individually (Sum multiple Auxiliary Transformers).
Identify values that are calculated if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility as appropriate

Data Type	Data Recorded	Last Verification (Previous Data)
Gross Reactive Power Generating Capability (*MVAR)		
Aux Reactive Power (*MVAR)		
Net Reactive Capability (*MVAR) equals Gross Reactive Power Capability (*MVAR) minus Aux Reactive Power (*MVAR)		
Gross Real Power Generating Capability (*MW)		
Aux Real Power (*MW)		
Net Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Power (*MW)		

* Note: Enter values at the end of the verification period.

Summary of Verification

- Date of Verification __________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Tap Settings: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient air temperature at the end of the verification period:

  Air temperature: _________°F Include in remarks below, any correction factor for different temperatures.
- The recorded MVAR values were adjusted to rated generator voltage, where applicable.
- Most recent verification Date used in table above ______________

Check all that apply:

☐ Overexcited Full Load Verification

☐ Underexcited Full Load Verification

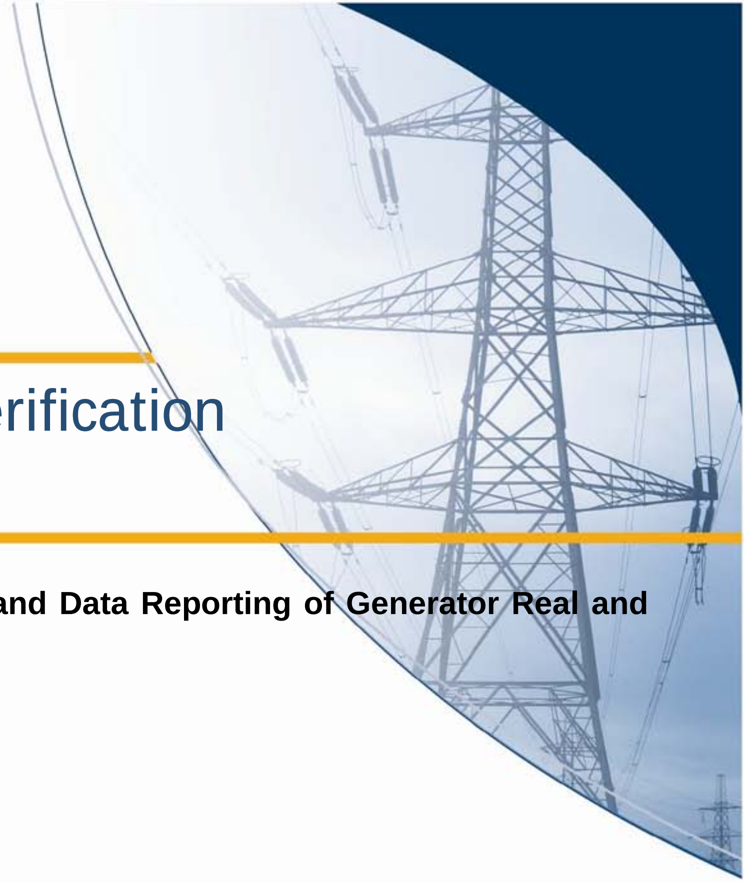
☐ Overexcited Minimum Load Verification

☐ Underexcited Minimum Load Verification

☐ Real Power Verification

Remarks :

Note: If the verification value did not reach the Thermal Capability Curve (D-Curve), describe the reason.



Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

Replace all requirements of MOD-025-1 and retire all requirements of MOD-024-1.

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of MOD-025-2:

- Transmission Owner
- Generator Owner

- Facilities

    - Individual generating unit > 20 MVA (gross nameplate rating) in a generating facility connected at the point of interconnection at 100 kV or above.
    - Generating plant/facility > 75 MVA (gross aggregate nameplate rating) and connected at the point of interconnection at 100 kV or above.
    - Blackstart units, regardless of size that are included in a Blackstart Capability Plan.
    - Synchronous condensers greater than or equal to 50 MVA.

Effective Date

In those jurisdictions where regulatory approval is required:

- By the first day of the next calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20% of its applicable units.

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- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40% of its applicable units.
- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60% of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80% of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units.

In those jurisdictions where regulatory approval is not required:

- By the first day of the next calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20% of its applicable units.
- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40% of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60% of its applicable units.
- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80% of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20% of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20% annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).

Proposed Action Plan and Description of Current Draft:

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4. Conduct initial ballot.	November 2011
5. Post response to comments.	December 2011
6. Conduct recirculation ballot.	January 2012
7. BOT adoption.	February 2012
8. File with regulatory authorities.	March 2012

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

2. **Number:** MOD-027-1

3. **Purpose:** To verify that the turbine/governor and Load control or active power/frequency control[1] model and the model parameters used in dynamic simulation that assess Bulk Electric System (BES) reliability accurately represent generator unit real power response to system frequency variations.

4. **Applicability:**

   4.1. Functional entities

   4.1.1 Generator Owner

   4.1.2 Transmission Planner

   4.2. Facilities

   For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants with an average capacity[2] factor greater than 5% over the last three calendar years that meet the following:

   4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

   - Each generating unit with a gross nameplate rating greater than 100 MVA, connected at the point of interconnection[3] at greater than 100 kV.
   - For each plant with a gross aggregate nameplate rating greater than 100 MVA, connected at the same point of interconnection at greater than 100 kV:
     - Each unit with a gross nameplate rating greater than 20 MVA; and
     - The remainder of the plant as an aggregate.

---

[1] Turbine/governor and Load control or active power/frequency control:

a. Turbine/governor and Load control applies to conventional synchronous generation.

b. Active power/frequency control applies to variable energy plants.

[2] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date.

[3] The common transmission bus voltage level at which the generator step up transformer is connected.

4.2.2 Generating units connected to the Western Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating greater than 75 MVA, connected at the point of interconnection[3] at greater than 100 kV.
- For each plant with a gross aggregate nameplate rating greater than 75 MVA, connected at the same point of interconnection t greater than 100 kV:
  - Each unit with a gross nameplate greater than 20 MVA; and
  - The remainder of the plant as an aggregate.

4.2.3 Generating units connected to the ERCOT Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating of greater than 50 MVA, connected at the point of interconnection[3] with rating greater than 100 kV.
- For each plant with a gross aggregate nameplate rating of greater than 75 MVA, connected at the same point of interconnection at greater than 100 kV:
  - Each unit with a gross nameplate greater than 20 MVA; and
  - The remainder of the plant as an aggregate.

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, three years following applicable regulatory approval:

- At least 25% of each Generator Owner’s applicable units per Interconnection on an MVA basis compliant with Requirement R2.
- 100% compliant with Requirements R1, and R3 through R5.

5.1.2 By the first day of the first calendar quarter, five years following applicable regulatory approval:

- At least 50% of each Generator Owner’s applicable units per Interconnection on an MVA basis compliant with Requirement R2.

5.1.3 By the first day of the first calendar quarter, seven years following applicable regulatory approval:

- At least 75% of each Generator Owner’s applicable units per Interconnection on an MVA basis compliant with Requirement R2.

5.1.4 By the first day of the first calendar quarter, nine years following applicable regulatory approval:

- 100% of each Generator Owner's applicable units compliant with Requirement R2.

5.2. In those jurisdictions where no regulatory approval is required:

5.2.1 By the first day of the first calendar quarter, three years following Board of Trustees adoption:

- At least 25% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.
- 100% compliant with Requirements R1, and R3 through R5.

5.2.2 By the first day of the first calendar quarter, five years following Board of Trustees adoption:

- At least 50% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.

5.2.3 By the first day of the first calendar quarter, seven years following Board of Trustees adoption:

- At least 75% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.

5.2.4 By the first day of the first calendar quarter, nine years following Board of Trustees adoption:

- 100% of each Generator Owner's applicable units compliant with Requirement R2.

B. Requirements

R1. Each Transmission Planner shall provide its Generator Owner with the following instructions and data within 30 calendar days of receiving a request from its Generator Owner for those instructions and data: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Instructions on how to obtain the list of acceptable turbine/governor and Load control or active power/frequency control system models for use in dynamic simulation.
- Instructions on how to obtain the Transmission Planner's software manufacturer's dynamic turbine/governor and Load control or active power/frequency control system model library block diagrams and/or data sheets.
- Any of the Generator Owner's existing unit or plant specific turbine/governor and Load control or active power/frequency control system data contained in the Transmission Planner's dynamic database from the current in-use model(s).

R2. Each Generator Owner shall provide a verified turbine/governor and Load control or active power/frequency control model (for each of its applicable Facilities) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1 to ensure modeling data is accurate for use in simulation software subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Each Generator Owner shall perform its verifications with one or more models acceptable to its Transmission Planner that collectively include the following information:

2.1.1. Documentation from the turbine/governor and Load control or active power/frequency control model verification activities including the on-line response compared to the recorded response for either a frequency excursion from a system disturbance, or a frequency reference change.

2.1.2. Type of governor and Load control or active power control/frequency control equipment.

2.1.3. A description of the turbine (e.g. for Hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer).

2.1.4. Turbine/governor and Load control or active power/frequency control model structure and data.

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, Load control, etc. but excluding AGC control) which would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R3. Each Generator Owner shall provide a written response that contains either the technical basis for maintaining the current model, a list of future model changes, or a plan to perform model verification[4] to its Transmission Planner within 90 calendar days of receiving written notice of one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Written notification, including a technical description from its Transmission Planner of why the turbine/governor and Load control or active power/frequency control model is not "usable" as identified in Requirement R5, Parts 5.1 through 5.3 criteria, or
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation, or
- Written comments and supporting evidence from its Transmission Planner indicating that the predicted turbine/governor and Load control or active power/frequency control response did not match the recorded response for three or more transmission system events.

R4. Each Generator Owner shall provide revised model data or plans to perform model verification to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and Load control or active power/frequency control system that

[4] If verification is performed, the 10 year period as outlined in Attachment 1 is reset.

alter equipment response [5] characteristic. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R5. Each Transmission Planner shall determine if the model meets the criteria identified in Requirement R5, Parts 5.1 through 5.3 and provide a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable. This written response shall be submitted within 90 calendar days of receiving the turbine/governor and Load control or active power/frequency control system verified model information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. The turbine/governor and Load control or active power/frequency control function model can initialize to compute modeling data without error.

5.2. A no-disturbance simulation results in negligible transients.

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping.

C. Measures

M1. The Transmission Planner shall have evidence to show that it provided requested instructions and data (such as dated electronic mail messages or mail receipts) within 30 calendar days of receiving a request as specified in Requirement R1.

M2. Each Generator Owner shall have evidence (such as dated electronic mail messages or mail receipts) including the verification report to show that it provided the verified turbine/governor and Load control or active power/frequency control model as specified in Requirement R2.

M3. Each Generator Owner shall have evidence to show that it provided a written response (such as a dated copy of the response, dated electronic mail messages or mail receipts) containing identified information and submitted within 90 calendar days of receiving any written notification as specified in Requirement R3.

M4. Each Generator Owner shall have evidence to show that it provided a written response (such as dated electronic mail messages or mail receipts) submitted within 180 calendar days of making system changes specified in Requirement R4.

M5. Each Transmission Planner shall have evidence to show that it provided a written response (such as dated electronic mail messages or mail receipts) within 90 calendar days of receiving the model as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

[5] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

Regional Entity

1.2. Data Retention

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest and previous turbine/governor and Load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 181 calendar days of receiving a request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 30 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Parts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1. OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Parts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Parts 2.1.1, through 2.1.5.	The Generator Owner failed to provide its verified turbine/governor and Load control or active power/frequency control[1] model(s) or failed to provide the verified model(s) no more than 90 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Parts 2.1.1, through 2.1.5.

R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice. (R3)	The Generator Owner failed to provide a written response within 181 calendar days of receiving notice as specified in Requirement R3. OR The Generator Owner's written response was provided within 181 calendar days of receiving written notice however failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and Load control or active power/frequency control[1] system that alter the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and Load control or active power/frequency control[1] system that alter the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and Load control or active power/frequency control[1] system that alter the equipment response characteristic. (R4)	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 271 calendar days of making changes to the turbine/governor and Load control or active power/frequency control[1] system that alter the equipment response characteristic as specified in Requirement R3.
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R5)	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 120 calendar days but less than 150 calendar days of receiving the verified model information. (R5) OR	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 150 calendar days but less than 180 calendar days of receiving the verified model information. (R5) OR	The Transmission Planner failed to provide a written response to the Generator Owner within 181 calendar days of receiving the verified model information as specified in Requirement R5. OR The Transmission Planner provided a

		The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and Load control or active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES General Meeting 2007, paper 07GM1307
2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005
3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004
4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004
5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004
6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Note that local grid codes may specify shorter time frames.

Facility	Condition	Periodicity
	Criteria 1: Verification Frequency Excursion Threshold: ≥ 0.05 hertz for the Eastern Interconnection, or ≥ 0.10 hertz for the ERCOT and Western Interconnections, or ≥ 0.15 hertz for the Quebec Interconnection from scheduled frequency. **Criteria 2:** Establishing the Recurring Ten Year Unit Verification Period Start Date: For each unit, the start date is set to either of the 25%, 50%, 75%, or 100% Standard implementation Effective Dates established as required for compliance in accordance with the nine calendar year transition period. or The start date is set to the actual date unit verification is performed.	
Existing Generating Unit	During each ten year unit verification period as established by Criteria 2 above. **AND** **No exceptions** apply. **AND** While the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to at least one BES frequency excursion as specified in Criteria 1 above.	A recorded unit Real Power response for a frequency excursion shall be collected during a ten calendar year (January - December) period with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected.
Existing Generating Unit	During each ten year unit verification period as established by Criteria 2 above. **AND**	Not Required (however, perform verification on a different unit each ten calendar

Facility	Condition	Periodicity
	The following unit exception applies: 1) Multiple units have the same MVA nameplate rating that are≤ 350 MVA **AND** 2) The same multiple units have identical applicable components and settings **AND** 3) The same multiple units are sited at the same physical location **AND** 4) The model for one of these equivalent units has been verified.	year cycle).
Existing Generating Unit	An acceptable frequency excursion at the generator from scheduled frequency **does not** occur during the ten calendar year (January - December) period and a staged frequency reference test is not performed **AND** The first time after the ten calendar year period while the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response and is subjected to a BES frequency excursion as specified in Criteria 1 above.	The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected.
Existing Generating Unit	Installation of new excitation control system equipment. **AND** The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to a BES frequency excursion as specified in Criteria 1 above.	The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected
Existing Generating Unit	Subjected to an activity resulting in an alteration of the response of the turbine/governor and Load control or active power/frequency control model. **OR** Receive written comments including dated electronic or hard copy evidence indicating that the recorded turbine/governor and Load control or active power/frequency control response for three or more Transmission System event did not match the predicted control system model response..	The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response

Facility	Condition	Periodicity
	OR Receive written comments detailing technical concerns with the Generator Owner's turbine/governor and Load control or active power/frequency control model verification documentation. **AND** The Generator Owner has submitted a verification plan. **AND** The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to a BES frequency excursion as specified in Criteria 1 above.	was collected
New or Existing Generator Unit	Excitation control system model identified as unusable by the Transmission Planner. **AND** The Generator Owner has submitted a verification plan. **AND** The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to a BES frequency excursion as specified in Criteria 1 above.	The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected
New Generating Unit	The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to aBES frequency excursion as specified in Criteria 1 above.	The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Requested

MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of MOD-027-1:

- Transmission Planner
- Generator Owner

- Facilities

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants with an average capacity[1] factor greater than 5% over the last three calendar years that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

[1] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date.

- Each generating unit with a gross nameplate rating greater than or equal to 100 MVA, connected at the point of interconnection [2] at greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating greater than or equal to 100 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:
    - Each unit with a gross nameplate rating greater than or equal to 20 MVA; and
    - The remainder of the plant as an aggregate.

Generating units connected to the Western Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating greater than or equal to 75 MVA, connected at the point of interconnection[2] at greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with at greater than or equal to 100 kV:
    - Each unit with a gross nameplate greater than or equal to 20 MVA; and
    - The remainder of the plant as an aggregate.

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Each generating unit with a gross nameplate rating of greater than or equal to 50 MVA, connected at the point of interconnection[2] with rating greater than or equal to 100 kV.
- For each plant with a gross aggregate nameplate rating of greater than or equal to 75 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:
    - Each unit with a gross nameplate greater than or equal to 20 MVA; and
    - The remainder of the plant as an aggregate.

Effective Date

In those jurisdictions where regulatory approval is required:

[2] The common transmission bus voltage level at which the generator step up transformer is connected.

By the first day of the first calendar quarter, three years following applicable regulatory approval:

- At least 25% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.
- 100% compliant with Requirements R1, and R3 through R5.

By the first day of the first calendar quarter, five years following applicable regulatory approval:

- At least 50% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.

By the first day of the first calendar quarter, seven years following applicable regulatory approval:

- At least 75% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.

By the first day of the first calendar quarter, nine years following applicable regulatory approval:

- 100% of each Generator Owner's applicable units compliant with Requirement R2.

In those jurisdictions where no regulatory approval is required:

By the first day of the first calendar quarter, three years following Board of Trustees adoption:

- At least 25% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.
- 100% compliant with Requirements R1, and R3 through R5.

By the first day of the first calendar quarter, five years following Board of Trustees adoption:

- At least 50% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.

By the first day of the first calendar quarter, seven years following Board of Trustees adoption:

- At least 75% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.

By the first day of the first calendar quarter, nine years following Board of Trustees adoption:

- 100% of each Generator Owner's applicable units compliant with Requirement R2.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 30-day formal comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post first draft revision of standard.	April-May 2011
2. Post response to comments and second version draft revision of standard.	July – August 2011
3. Post response to comments and request authorization to ballot the revised standard.	September - October 2011
4. Conduct initial ballot.	November 2011
5. Post response to comments.	December 2011
6. Conduct recirculation ballot.	January 2012
7. BOT adoption.	February 2012
8. File with regulatory authorities.	March 2012

A. Introduction

1. Title: Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

2. Number: PRC-019-1

3. Purpose: To improve the reliability of the Bulk Electric System by preventing tripping of generating units and generating Facilities due to mis-coordination of generating unit and generating Facility voltage regulating controls and limit functions with generator capabilities and protection system settings.

4. Applicability:

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner

4.2. Facilities

4.2.1 Individual generating unit or synchronous condenser > 20 MVA (gross nameplate rating) connected at the point of interconnection at 100 kV or above.

4.2.2 Generating plant and generating Facility > 75 MVA (gross aggregate nameplate rating) connected at the point of interconnection at 100 kV or above.

4.2.3 Blackstart Resources, regardless of size included in a Transmission Operator's restoration plan.

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20% of its applicable units.

5.1.2 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40% of its applicable units.

5.1.3 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60% of its applicable units.

5.1.4 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80% of its applicable units.

5.1.5 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20% of its applicable units.

5.2.2 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40% of its applicable units.

5.2.3 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60% of its applicable units.

5.2.4 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80% of its applicable units.

B. Requirements

R1. Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate its generating unit and generating Facility voltage regulating system controls, including limiters and protection functions with the generating unit and Facility or synchronous condenser capabilities and protective system settings; to include as applicable: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- In-service [1] excitation system and voltage regulating system control, limiters and protection functions
- In-service generator or synchronous condenser protection system settings
- Generating equipment or synchronous condenser capabilities
- Steady state stability limit

1.1. This coordination requires the following steps:

1.1.1. Verify that the limiters are set to operate before the protection and the protection is set to operate before conditions exceed equipment capabilities (including the steady state stability limit) assuming normal AVR control loop and system steady state operating conditions.

1.1.2. Check that the settings determined in Step 1.1.1 are applied to the in-service equipment.

1.2. Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within

[1] Limiters or protective functions that are installed and activated on the generator or synchronous condenser.

90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following

- Voltage regulating equipment changes
- Protection system settings or component changes
- Generating or synchronous condenser equipment capability changes
- Generator or synchronous condenser step-up transformer changes

C. Measures

M1. Each Generator Owner and Transmission Owner will have evidence, such as example plots provided in PRC-019 Section G, to show that its generating unit and generating Facility or synchronous condenser excitation system and voltage regulating system controls and protection functions are coordinated with the generating unit and generating Facility capabilities and protective system settings applied to in-service equipment as specified in Requirement R1, Section 1.1, and one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2. If the latest coordination review is performed due to a change in the equipment or settings that changes the coordination, the Generator Owner and Transmission Owner will have evidence (such as a work order) that demonstrates when the change was implemented.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Generator Owner and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner and Transmission Owner shall retain the latest and the prior evidence of compliance with Requirement R1, Measure M1.

If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change that affected the coordination.	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change that affected the coordination.	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change that affected the coordination.	The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 at least once every five years. OR The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 within 121 calendar days following the identification or implementation of a change that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of one or more plots including (but not limited to):

- P-Q Diagram (Attachment 1), or
- R-X Diagram (Attachment 2), or
- Inverse Time Diagram (Attachment 3)

These plots contain the equipment capabilities, the operating region for the limiters and protection function such as; under-excitation limiters, steady state stability limits, or loss of field protection curves. Additional limiters and protection function that are installed and in-service can be incorporated as an Inverse Time Limit/Protection Characteristic Plot (Attachment 3) or into the Generator Reactive Capability Curve Plot or an R-X diagram plot, identified above.

Equipment limits, types of limiters and protection functions which could be coordinated include:

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.
- Converter over-temperature limiter and associated protection function.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

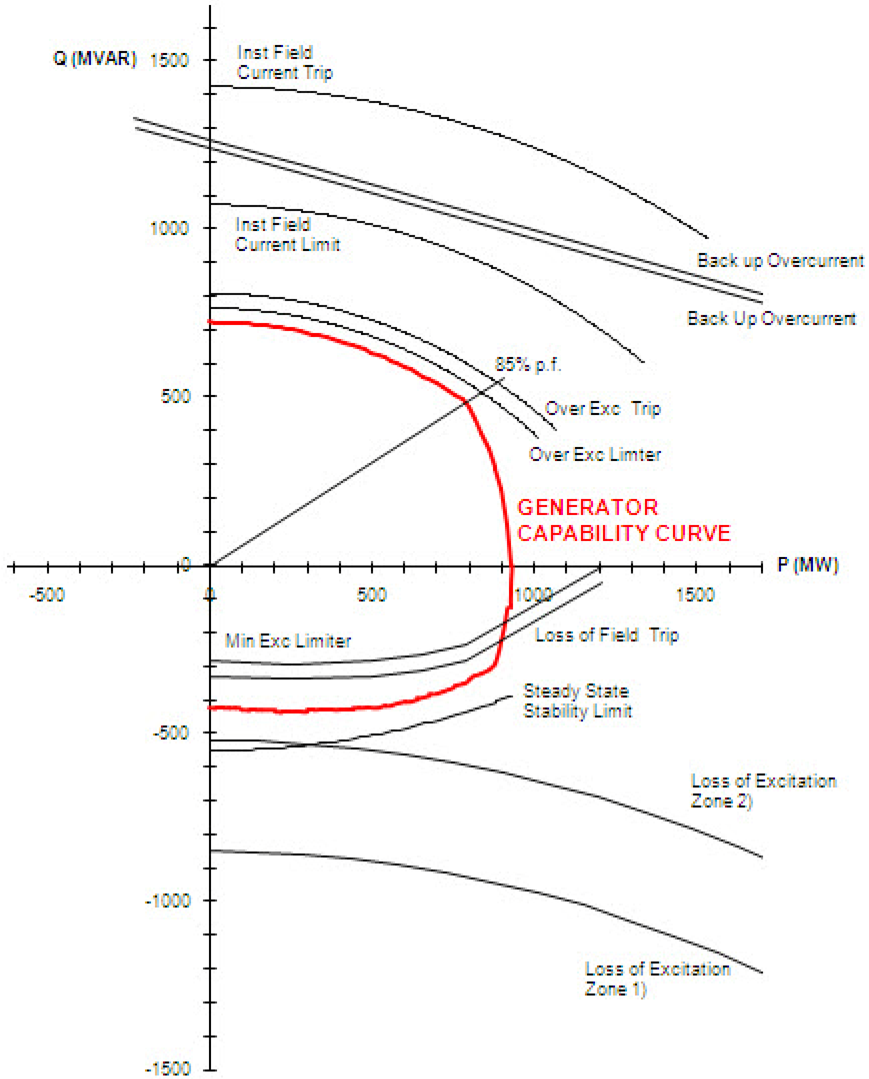
On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$
$$R = V^2_g*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

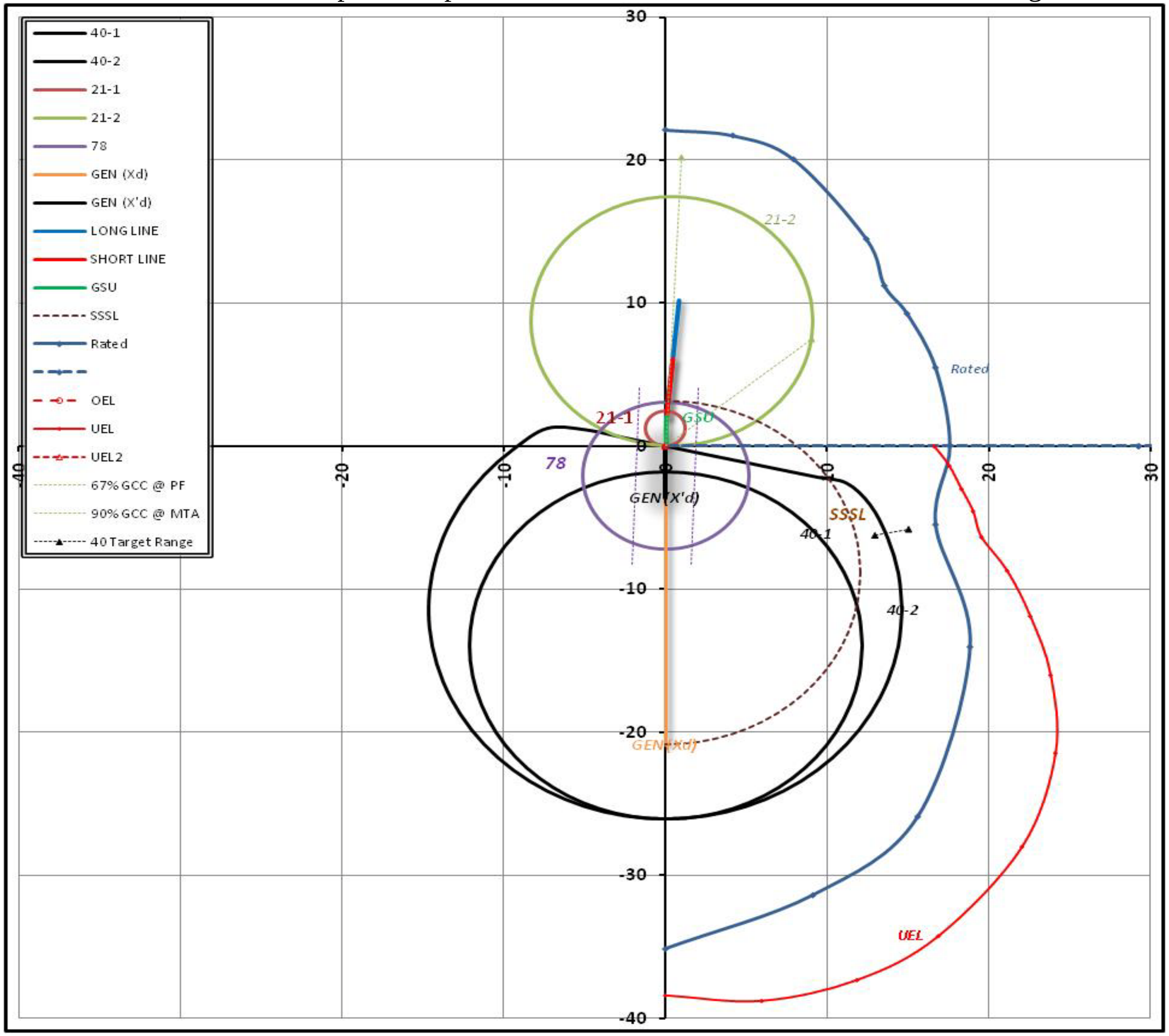
$$C = (X_d-X_s)/2$$
$$R = (X_d+X_s)/2$$

Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram

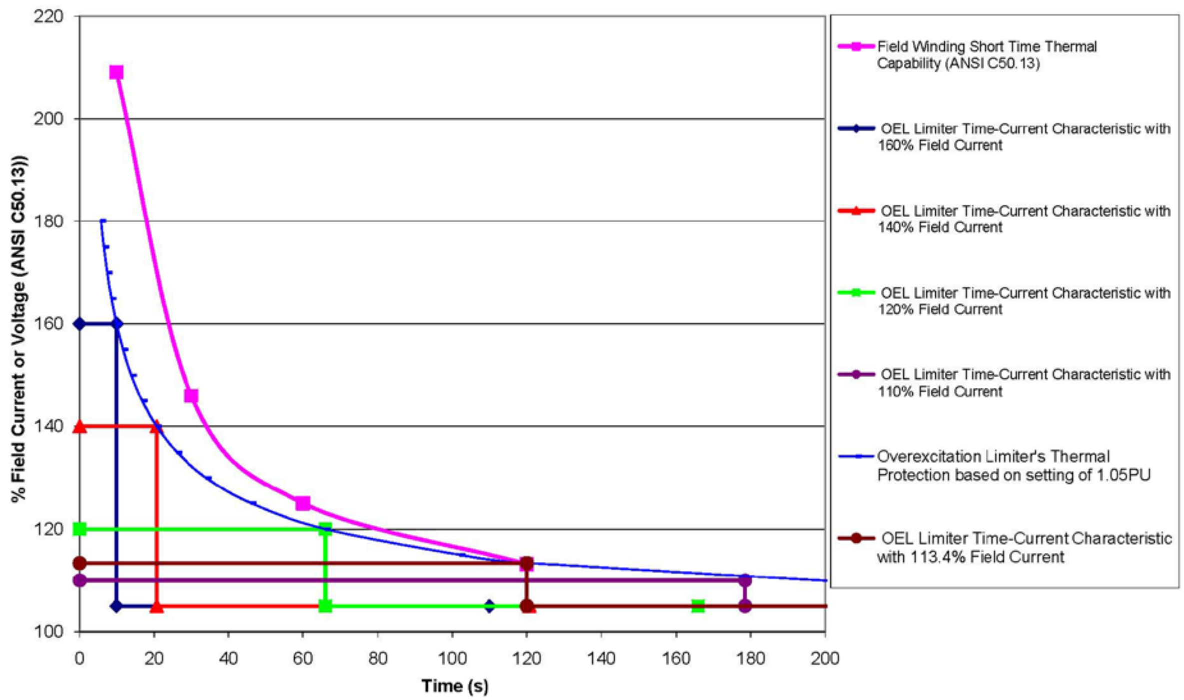


Example of Generator Capability Curve with Protection Elements Visible

Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram



Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for PRC-019-1, Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

Approvals Requested:
PRC-019-1 - Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of PRC-019-1:

- Transmission Owner
- Generator Owner

- Facilities:
  - Individual generating unit and synchronous condenser > 20 MVA (gross nameplate rating) in a generating Facility connected at the point of interconnection at 100 kV or above.
  - Generating plant/Facility > 75 MVA (gross aggregate nameplate rating) and connected at the point of interconnection at 100 kV or above.
  - Blackstart units, regardless of size included in a Blackstart Capability Plan.

Effective Date

The first day of the first calendar quarter two years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 20% of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter two years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 40% of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter three years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 60% of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter four years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter four years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 80% of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter five years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter five years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have 100% of applicable units and facilities fully compliant with this standard.

Justification for Phasing:

The coordination activities in this standard (PRC-019) are most effectively performed just prior to the performance of a reactive capability test as required by MOD-025. Hence, the SDT has followed the same implementation schedule in PRC-019 as defined in MOD-025.

Unofficial Comment Form for Generator Verification (Project 2007-09)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the First Posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09). The electronic comment form must be completed by **July 15, 2011.**

Project 2007-09 Generator Verification

If you have questions please contact Stephen Crutchfield at Stephen.Crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024 — Verification of Generator Gross and Net Real Power Capability.
- MOD-025 — Verification of Generator Gross and Net Reactive Power Capability.

And four draft standards developed by the Phase III & IV SDT that were fielded tested by four Regions from mid 2006 through mid 2007.

- PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024 — Generator Performance During Frequency and Voltage Excursions
- MOD-026 —Verification of Models and Data for Generator Excitation System Functions
- MOD-027 — Verification of Generator Unit Frequency Response

Before beginning the detailed work of developing the standards, the SDT was presented the recently completed field test results by the participants from the four field test Regions. The SDT also reviewed how and to what extent the two NERC Board approved standards were used across all the Regions.

Based on comments received from the first posting of MOD-024-2 the SDT is proposing that the Requirements for MOD-024-1 be combined with the Requirements of MOD-025-1 into a single standard, MOD-025-2. The SDT concluded that combining MOD-024-1 and MOD-025-1 would enhance the accuracy of the model for the high demand system conditions because MOD-025-2 would prove the unit's Real Power capability when the unit was producing maximum Reactive Power.

MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power Capability was developed with consideration to key issues stated in the SAR:

- Provide more details to the applicability section
- Replace the "fill in the blanks" requirements assigned to the Regional Reliability Organization with a set of "continent-wide" requirements
- Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization
- Consider and address issues identified in FERC orders, including the modifications to MOD-024-1 and MOD-025-1 as proposed in FERC Order 693
- Consider and address issues identified during Phase III & IV field testing

The SDT realizes that the data points produced by the MVAR verification required in MOD-025-2 may not duplicate the manufacturer supplied thermal capability curve (D-curve) due primarily to transmission system conditions. However, the MOD-025-2 verification may be able to uncover some unit limitations such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc. which could then be studied further for resolution. For verifications that are limited primarily by transmission system conditions the resulting verified MVAR value is probably not the value that should be entered into the Transmission Planner's database. It is also likely not the same value that is submitted per MOD-010. While not required by the draft standard it is permissible to perform engineering analysis to determine the expected capabilities of the unit under less restricting system conditions. Although the engineering analysis will not physically verify the complete MVAR capability it is a reasonable estimate of unit capability that the transmission planner can use in his model. The SDT has also allowed the use of either operational data or staged testing for the verification. This allows the Generator more flexibility to obtain the best possible conditions for uncontrollable parameters such as wind speed, solar irradiance, and transmission system voltage conditions during the verification. When operational data is used, the SDT has required that the verification fall within 20% of the expected value. The limit is a compromise, based on engineering judgment, and input is solicited from industry on what this limit should be.

The SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability". Approximately 4% of the overall system capacity is connected at a voltage less than 100kV. The SDT concluded that 4% was not an impact on reliability, and did not require verification of units connected below 100kV. The SDT has proposed that this standard be consistent with the more general Compliance Registry Guidelines. If regions have generating units that are connected at under 100 kV that are important to the reliability of the system due to some local consideration, then the region has the authority to require that those units be verified if they so choose.

In line with minimizing potentially unnecessary work by the Generator Owner and providing maximum benefit to the Transmission Planner, the SDT has developed a "diagram" guideline in the form of Attachment 2 to the standard. The Attachment can be used directly or modified as necessary to reflect the dozens of actual installation configurations. The Attachment sets the basic structure and data needed. The visual diagram provides for easier entry by the Generator Owner and application of information for Transmission Planner simulation models.

The SDT discussed if standard MOD-025-2 should also include verification of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers, although some are owned by Generators. The SDT proposes that synchronous condensers be verified under MOD-025-2 also since they are also rotating synchronous machines, subject to the same issues that synchronous generators are subject to, and their output should be verified periodically to insure they can deliver their rating if required.

The following questions will assist the SDT in finalizing the development of MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power capability. For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. To improve this first draft of MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power capability, the SDT would appreciate responses to as many of these questions as you can answer.

The SDT has provided a mapping of the current NERC Board approved MOD-025-1 requirements to the proposed MOD-025-2 requirements as part of the Implementation Plan. Since the SDT is proposing to put the requirements of the existing MOD-024-1 into MOD-025-2, a second mapping document of the MOD-024-1 requirements to MOD-025-2 is also provided.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT has proposed that the requirements of MOD-024-1 and MOD-025-1 be combined into a single standard MOD-025-2. Do you agree with this approach? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has proposed that the data from MOD-025-2 be submitted to the Transmission Owner. Do you believe the Transmission Owner is the appropriate entity to receive this data? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

3. The SDT has proposed that the ambient temperature during the verification be provided to the Transmission Owner as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature if needed. Do you feel the standard should require that the Real Power data submitted be temperature adjusted to some other than ambient temperature? If yes, please explain and include which entity you think should perform the correction and which entity should determine the temperature value that should be used for the correction.

   ☐ Yes

   ☐ No

   Comments:

4. The SDT believes that verification should be performed on units that are connected down to 100 kV. The SDT has also provided how verification should be handled in plants/facilities that are greater than 75 MVA in aggregate gross nameplate rating. The Standard requires a separate verification for every unit greater than 20 MVA gross nameplate rating. This is consistent with the current Compliance Registry. Units 20 MVA and smaller, in a plant/facility greater than 75 MVA, can be verified separately or in aggregate as the Generator Owner chooses. Do you agree with the SDT's decision to have the Standard be applicable to the compliance registry? If not, please explain.

   ☐ Yes

   ☐ No

   Comments:

5. The draft standard requires that the Reactive Power capability be verified at four points: over-excited (lagging) and under-excited (leading) reactive capability at (1) the rated Real Power capability and (2) expected minimum Real Power output. The SDT believes

that this is consistent with the FERC directive in Order 693 at P1321, “Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit’s operating range.” Do you agree that the four points proposed by the SDT is adequate to provide a straight line approximation to a unit’s Reactive Power capability over its actual operating range? If not, please explain.

☐ Yes

☐ No

Comments:

6. Verification of over-excited reactive capability at rated Real Power Capability is required to be conducted over a minimum of one hour. Do you agree with the verification time? If not, please explain.

☐ Yes

☐ No

Comments:

7. Verification of (1) under-excited reactive capability at rated Real Power of the most recent gross verified Real Power capability reported, (2) under-excited reactive capability at expected minimum Real Power output and (3) over-excited reactive capability at expected minimum Real Power output, are all to be recorded as soon as a limit is encountered. Do you agree that such data recorded as soon as a limit is encountered is appropriate for such verification? If not, please explain.

☐ Yes

☐ No

Comments:

8. Synchronous condensers are also reactive resources that may be important to reliability, but they are not generators. The SDT proposes that synchronous condensers be verified under MOD-025-2. Do you feel that this is appropriate?

☐ Yes

☐ No

Comments:

9. The SDT proposes that the size of synchronous condensers to be verified be limited to those greater than 50 MVA. Do you feel that this size criterion for synchronous condenser verification is appropriate?

☐ Yes

☐ No

Comments:

10. Either operational data or staged testing is allowed by the standard for verification. Do you agree that these two methods of verification are acceptable? If not, please explain.

☐ Yes

☐ No

Comments:

11. If operational data is utilized, the standard requires the verification be within 20% of the expected value. Do you agree with the 20% requirement? If not, please explain.

☐ Yes

☐ No

Comments:

12. Are you aware of any regional variances that would be required for this standard?

☐ Yes

☐ No

Comments:

13. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

☐ Yes

☐ No

Comments:

14. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please provide a reference to the section, requirement or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal.

☐ Yes

☐ No

Comments:

Unofficial Comment Form for Generator Verification (Project 2007-09)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the First Posting of MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Project 2007-09). The electronic comment form must be completed by **July 15, 2011.**

Project 2007-09 Generator Verification

If you have questions please contact Stephen Crutchfield at Stephen.Crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The purpose of Project 2007-09 - Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).

- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024-1 — Verification of Generator Gross and Net Real Power Capability.

- MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability.

And four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007.

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit
- Capabilities and Protection

- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions

- MOD-027-1 — Verification of Generator Unit Frequency Response

This is the second posting of standard MOD-026-1 Verification of Models and Data for Generator Excitation Control System Functions for industry review. It should be noted that the title of the standard has been changed from "Verification of Models and Data for Generator Excitation Control System Functions" to "Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions" in order to reflect the SDTs inclusion of plants with several small units, in large part to include Variable Energy Resource plants (discussed in more detail below). The second posting of standard MOD-026-1 Verification of Models and Data for Generator Excitation Control System Functions was developed with consideration of industry response to questions that were posed as part of the Comment Form accompanying the first posting. This posting also includes the initial posting of standard MOD-027-1. Note for the same reason discussed for standard MOD-026-1, standard MOD-027-1 has been re-titled from “Verification of Generator Unit Frequency Response” to “Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions”. While there are a few differences between standards MOD-026-1 and MOD-027-1 as detailed below, there are also many similarities. The two standards are similar in both substance and style.

Standard MOD-027-1:

There are many similarities between standards MOD-026-1 and MOD-027-1 since both address verification of dynamic models of critical generation control functionality. These similarities are:

1) Based on industry feedback and consultation with the NERC Functional Model Working Group (FMWG), the Generator Owner was identified as the appropriate entity to assign dynamic model verification responsibility. It is up to the Generator Owner and Generator Operator to define contractual arrangements needed to comply with requirements of these standards.
2) As a baseline, the SDT recognized that the excitation system models and model data are already collected through the processes identified in standards MOD-012 and MOD-013. This information, with few exceptions, already establishes a quality dynamics database. However, as confirmed through field testing, performing verification activities specified in the draft standard will improve the accuracy of exciter models used in dynamic simulation which are used to determine transmission security limits. Therefore, both standard drafts propose an identical base Applicability requiring verification of the dynamic models associated with 80% or greater of the connected MVA per Interconnection.
3) The majority of industry agreed with the standard MOD-026-1 5% capacity factor threshold for dynamic model verification. This same threshold is proposed in this current draft of standard MOD-027-1.
4) Both draft standards contain the philosophy of allowing excitation control system verification for a single unit to satisfy compliance for other units if certain conditions are met (such as having the same MVA rating, having identical applicable components and settings, and being sited at the same physical location).
5) Based on an industry comments from the first posting of MOD-026-1 and technical justification regarding the nameplate MVA of steam units for existing Combined Cycle plant technology, the proposed threshold MVA nameplate rating is ≤350 MVA in both standards.
6) Both draft standards contain a standalone Periodicity Table. The Periodicity Table provides the base ten year applicability timeframe for collecting data needed to perform verification (note: standard MOD-027 exceptions may apply as discussed below). The Periodicity Table also addresses scenarios which could require additional testing and subsequent model re-verification. The Periodicity Table will enable Generator Owners to quickly determine required retest dates for model verification.
7) Both draft standards have similar phase in periods that includes allowances for verification performed using Regional procedures that are applicable for the first 10 year period.

Differences also exist between MOD-026-1 and MOD-027-1:

1) The implementation plan for standard MOD-027-1 is structured to recognize that Generator Owners will either need to install equipment to record the real power output of units during an appropriate frequency excursion or modify the existing recording equipment (such as frequency triggers, recording time, etc.). The proposed implementation plan specifies compliance with R2 at intervals of 25% of applicable units per Interconnection on a MVA basis three years after the effective date, 50% at five years, 75% at seven years, and 100% at nine years. Compliance with R2 as per the Periodicity Table (Table 1), means that beginning on the implementation date, the Generator Owner has 10 years to obtain an appropriate recorded response, and 2 years after obtaining the appropriate recorded response to verify the model (see Item 4 below that discusses exceptions to the aforementioned timeframe).

2) Like the draft standard for verification of excitation control system models, this draft standard allows for both staged tests and for ambient monitoring. However, the SDT expects that the majority of turbine/governor and load control functions will be verified through ambient monitoring. To ensure the impact of outer loop controls is captured and replicated in the model, the standard allows staged tests where a frequency reference change is applied if the unit is on-line. This type of test is not common. Many units do not have a frequency reference change input where such a signal can be applied. Therefore, the SDT recognized that the Generator Owner's opportunity to verify that the predicted model response matches the recorded response for an appropriate system frequency excursion will often be dependent on its unit being on-line and in an operating state to respond to the system frequency excursion when it occurs. The basis for this strategy is:

    a. Large economical units have a higher probability of being on-line in a proper operating state to experience a frequency excursion requiring model verification.
    b. Units which are not on-line or not in a proper operating state will not help arrest the frequency excursion. Even if this is not the case, it is better to experience an event for model verification as opposed to relying on a survey that may be inaccurate.

3) In the current draft of MOD-026, the Generator Owner has one year from the capture of a voltage excursion to verify the excitation control system model. This timeframe is based on the SDT's belief that the majority of exciters will be verified using a staged test; and if ambient monitoring is utilized, there will be frequent naturally occurring transmission system voltage excursions. Since the SDT anticipates that the majority of the units' turbine/governor and load control models will be verified utilizing ambient monitoring, it is recognized that it is appropriate to give the Generator Owner time to retrieve captured data. Unlike ambient voltage excursion data needed for excitation control system model verification, the unit must be in an operating state that would allow the unit to respond to the frequency excursion. Also, it is likely that the number of acceptable frequency excursions (from a compliance perspective) will be significantly fewer than the number of acceptable voltage excursions that would occur for model verification. Therefore, the SDT decided to allow the Generator Owner two years for verifying the model. This timeframe allows adequate time

to a) realize the event has occurred while the unit was in the proper operating state, and b) to verify the model. This timeframe will also assist the Generator Owner with planning contractor, budget and schedule support if activities are outsourced.

4) A unit has to be on-line and in the proper operating state during a frequency excursion in order to capture an effective real power response for model verification. Therefore, the standard provides time for the Generator Owner to capture and record a response requiring verification, even if it takes longer than ten years to do so. This language, which is contained in the Periodicity Table, is specifically crafted so that extension of the ten year periodicity cycle will only happen if a frequency excursion does not occur with the unit on-line and in the proper operating state. Therefore, the lack of installed and operating recording equipment during a frequency excursion is not a valid excuse for obtaining a ten year timeframe extension.

5) Industry experience has shown that a unit's real power response to a system frequency excursion could be different from one event to the next. Reasons include different unit load levels, prime mover control conditions, operator control mode, and magnitude of the frequency deviation. By contrast, excitation control system responses to system voltage excursions are much more consistent. Therefore, the main model verification requirement (R2 Part 2.1.1) calls for the turbine/governor and load control model to be "compared to" the recorded response of actual equipment whereas in standard MOD-026-1, the wording is "matches".

6) In standard MOD-026-1 R3, there is a process where a Transmission Planner can make a written request, including evidence that the excitation control system (or plant volt/var) model response did not match an actual recorded response, to the Generator Owner which essentially requires the Generator Owner to review the model. While there is similar language in standard MOD-027-1 R3, there is the additional stipulation that the Transmission Planner must include supporting evidence of instances where model response did not match an actual recorded response. The reason for this is that the governor response is not consistent enough from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. In fact, while the fundamental requirement for verifying the model once every ten years can be satisfied by taking into account only a single frequency excursion, it is strongly recommended that model verification be performed taking into account multiple frequency excursions (if available and assuming the unit was in a proper operating state as required for model verification).

7) The activity specified in Requirement R4 is similar to draft standard MOD-026-1 Requirement, R4 which lists the evidence of compliance that the Generator Owner must maintain whenever certain activities occur that alter the equipment response; resulting in providing either revised model data or re-verifying the model. Unlike excitation control systems, there are many control parameters associated with the turbine/governor and load control system which will not impact equipment performance that is required to be replicated in the dynamic model. Thus, standard MOD-027-1 Requirement R4 is specifically crafted to only include setting changes for droop, and/or dead band, and/or load control mode.

Since it is likely that many Generator Owners will rely on the expertise of consultants to make the determination of how modifications to droop, dead band, and/or load control mode translate into modified model parameter values, a time period of 180 days is proposed.

8) In MOD-026-1, the SDT is proposing a process where the Planning Coordinator can request a review of an excitation control system model for a unit not specified in the standard Applicability section. The new MOD-026-1 Requirement (R5) was added in response to industry comments. It requires the Planning Coordinator to supply technical justification that demonstrates either a) the unit affects a stability limit, or b) the simulated unit response does not match a measured unit response (most likely captured during a system disturbance event). However, this process is not being proposed for MOD-027-1. It is extremely unlikely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit. Also, as already discussed (Item 6), governor response is not consistent from one frequency excursion event to the next. Therefore, the SDT did not feel that such a Requirement in MOD-027-1 was necessary.

9) There is no need for the Transmission Planner to provide the generator MVA base when providing models for turbine/governor and load control or active power/frequency control systems. The MVA base associated with the generator model is already required to be provided per Requirement R1 of standard MOD-026. The MW base information is reflective of turbine capability and is provided as one of the turbine/governor and load control model data parameters specified. The MW base information, depending on the dynamic simulation software provider model requirements, will either be in the form of an actual MW value or a per unit MW value; with the base being the MVA value that is used in the generator steady state model.

10) The Generation Verification SDT is closely following and coordinating with the Frequency Response SDT. It is hoped that the Frequency Response SDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, though the Frequency Response SDT has discussed this concept and is investigating the use of a tool to help facilitate the identification of appropriate frequency excursions, the process is still evolving. As an interim step, the Generation Verification SDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine/governor and load control functions for the purpose of model verification and b) would be expected to occur 15 times a year or more. If by chance a process identifying frequency excursions that can be utilized in support of standard MOD-027-1 requirements is not developed by the Frequency Response SDT, then such a process will have to be proposed for future revision to standard MOD-027-1 by the Generation Verification SDT.

Compliance Elements for MOD-027-1:

The SDT added Compliance Elements to the second posting of the standard. The VRF for Requirement, R1-R5 are all designated as low risk. All of these Requirements provide for an update of dynamic modeling data for an existing unit. Violation of these requirements would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system, which is consistent with the low risk level guidelines.

The VSL for R2 was selected using the metric of “Requirements with Parts that Contribute Equally to the Requirement”. All of the items listed in Requirement R2 are required for successful model verification. The remaining VSLs were selected using the metric of “Increments for Tardiness”. The Requirements cover activities that are not typical such as peer reviews and instances where there is concern that the model does not reliably reflect actual equipment performance. As such, timeliness of communications is paramount.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The Applicability section of MOD-027 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability?

   ☐ Yes

   ☐ No

   Comments:

2. Because it is not likely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit, and because governor response is not consistent from one frequency excursion event to the next, the SDT is not proposing a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section.

   Do you agree with the proposal to not include a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section?

   ☐ Yes

   ☐ No

   Comments:

3. The SDT discussed if MOD-027-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR.

   Do you agree with the proposal to not include the verification of synchronous condensers in MOD-027-1?

   ☐ Yes

   ☐ No

   Comments:

4. Are you aware of any regional variances that would be required as a result of MOD-027-1? If yes, please identify the regional variance.

☐ Yes

☐ No

Comments:

5. Are you aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

   ☐ Yes

   ☐ No

   Comments:

6. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain.

   ☐ Yes

   ☐ No

   Comments:

Unofficial Comment Form for Generator Verification (Project 2007-09)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the First Posting of PRC-019-1, Coordination of Generating Unit/Facility Voltage Regulating Controls with Generating Unit/Facility Capabilities and Protection (Project 2007-09). The electronic comment form must be completed by **July 15, 2011.**

Project 2007-09 Generator Verification

If you have questions please contact Stephen Crutchfield at Stephen.Crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The purpose of Project 2007-09 Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).

- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024-1 — Verification of Generator Gross and Net Real Power Capability.

- MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability.

And four draft standards developed by the Phase III & IV SDT that were fielded tested by four Regions from mid 2006 through mid 2007.

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions

- MOD-027-1 — Verification of Generator Unit Frequency Response

This is the first posting of standard PRC-019-1, Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection. The SAR instructs that the draft standard PRC-019-1:

☐ Revise the purpose statement to include the reliability-related benefit of the standard.

- ☐ Provide more details to the applicability section of the standard to identify any generators that should be exempt from compliance with the requirements in the standard.
- ☐ Replace the requirements assigned to the Regional Reliability Organization with a set of requirements that has more specificity and includes a set of ‘continent-wide’ criteria for verification that generator voltage regulator controls and limit functions are coordinated with the generator’s capabilities and protective relays.
- ☐ Assign responsibility to the appropriate functional entities as a result of updates to the functional model and the replacement of the requirements assigned to the Regional Reliability Organization.
- ☐ Add a ‘violation risk factor’ and a ‘time horizon’ for each requirement (later).
- ☐ Update all the compliance sections of the standard, including:
  - Update the compliance monitoring section to clarify that the Regional Entity will be the compliance monitor for the Generator Owner.
  - Replace the ‘levels of non-compliance’ with ‘violation severity levels’ (later).

This draft standard was developed after reviewing the applicable FERC order, the results of field testing, and in accordance with the Generator Verification SAR. A standard PRC-019 sub-team developed an initial draft framework and then completed the details of the standard and reviewed the requirements and proposals with the full Generator Verification SDT.

The purpose of this standard is to improve the reliability of the Bulk Electric System by preventing tripping of generating units/facilities due to mis-coordination of generating unit/facility voltage regulating controls and limit functions with generator capabilities and protection system settings. The activities required by this standard are also important and complementary for a generating unit or facility to meet the reactive power capability testing requirements of the proposed standard MOD-025. The SDT considered combining the two standards, but ultimately decided that the coordination of controls, limits and protective functions, while linked to reactive testing, has a distinct reliability purpose that is different than MOD-025. The coordination to prevent tripping is clearly a different reliability purpose than the testing of reactive power capability for modeling verification.

Applicability:

The Generator Owner is the functional entity that has responsibility for performing the evaluations required in this Standard for its registered generating equipment (including synchronous generators and non-synchronous generating equipment that incorporates voltage control at the unit or facility level). Transmission Owners who own synchronous condensers ≥ 50 MVA are responsible for performing the evaluations required in this Standard for such equipment. The intent of the Applicability section is to capture all equipment that is required to meet the reactive power capability verification requirements.

Implementation:

The SDT believes this standard will be used by the Generator Owner/Transmission Owner in conjunction with (or as a preliminary task to) reactive power capability testing (standard MOD-025-2), and has aligned the (Proposed) Effective Dates of this standard to those of standard MOD-025-2. The proposed effective dates provide a “phased-in” approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/facilities.

Requirements and Measures:

Requirement R1 defines the obligation to perform an evaluation of the coordination of generating unit or facility voltage control limiters with associated protective functions and equipment capabilities. The evaluation is to consider operation under steady state and normal AVR control loop conditions.

The requirement describes this coordination to entail the following aspects:

A) Determine settings are correctly sequenced to ensure that the limiters are set to operate before the protection and the protection is set to operate before conditions exceed equipment capabilities, including the steady state stability limit when operating within the normal AVR control loop and under steady state operating conditions.
B) Check that the settings as determined in Step A are applied to the in-service equipment.

Examples of diagrams and the equipment capabilities, voltage control limiters, and protective function characteristics that demonstrate coordination are included in Section G, “Reference – Examples of Coordination.”

The standard does not require the installation or activation of any of the aforementioned limiters or protective functions.

Requirement R2 defines the obligation to review the evaluation performed in R1 at least once every five years, or within 90 days of making a change to the generating equipment, voltage control limiter settings, or protective function settings that would affect the coordination. The periodicity was set to correlate with the periodicity of verification of reactive power capability defined in Standard MOD-025.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that the standard, as written, is "technology neutral" such that it can be used for all forms of generation connected to the BES? If you do not agree, please state your reasons and suggest alternatives to make the standard technology neutral in the Comment area.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 50 MVA. The standard applies to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 50MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the Comment section.

   ☐ Yes

   ☐ No

   Comments:

3. As currently drafted this standard applies to synchronous generators, synchronous condensers, and variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites). Do you see a reliability need for including variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites in this standard? Please explain your answer in the Comments block.

   ☐ Yes

   ☐ No

   Comments:

4. The SDT revised the Purpose of the standard in accordance with the SAR. "To improve the reliability of the Bulk Electric System by preventing tripping of generating units/facilities due to mis-coordination of generating unit/facility voltage regulating controls and limit functions with generator capabilities and protection system settings."

   Do you agree with the revised Purpose of the standard? If not, please provide suggested language changes in the Comment section.

   ☐ Yes

   ☐ No

   Comments:

5. The proposed effective dates provide a "phased-in" approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/facilities. Do you agree with the proposed implementation schedule? If not,

please provide an alternative implementation schedule, approach and supporting information in the comments.

☐ Yes

☐ No

Comments:

6. Do you agree that the evidence documents and functions listed in Section G are sufficient for giving the Generator Owner/Transmission Owner examples of how the coordination can be demonstrated? If not, please provide suggested language changes to the Measure and supporting information in the Comment section.

☐ Yes

☐ No

Comments:

7. Do you agree with the Data Retention language listed in the Compliance section of the draft standard? If not please comment and provide alternative Data Retention language.

☐ Yes

☐ No

Comments:

8. Are you aware of the need for any regional variances to this standard? If yes, please explain in the comment section.

☐ Yes

☐ No

Comments:

9. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain in the comment section.

☐ Yes

☐ No

Comments:

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Real Power Capability**

2. **Number:** MOD-024-1

3. **Purpose:** To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Effective Dates:**

   Requirement 1 and Requirement 2 **—** April 1, 2006.

   Requirement 3 — January 1, 2007.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:

- **R1.1.** Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.
- **R1.2.** Criteria for reporting generating unit auxiliary loads.
- **R1.3.** Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.
- **R1.4.** Periodicity and schedule of model and data verification and reporting.
- **R1.5.** Information to be verified and reported:
  - **R1.5.1.** Seasonal gross and net Real Power generating capabilities.
  - **R1.5.2.** Real power requirements of auxiliary loads.
  - **R1.5.3.** Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Real Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Real Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to those procedures, for verification and reporting of generator gross and net Real Power capability were provided to affected Generator Owners, Generator Operators,

Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Real Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous versions of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2, R1.4

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: There shall be a level two non-compliance if **both** of the following conditions are present:

2.2.1 Procedures did not meet two of the following requirements: R1.1, R1.2, R1.4

2.2.2 No evidence that procedures were distributed as required in R2.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet either R1.5.1, R1.5.2 or R1.5.3

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a generator owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a generator owner’s units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a generator owner’s units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% of a generator owner’s units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Reactive Power Capability**

2. **Number:** MOD-025-1

3. **Purpose:** To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Effective Dates:**

   Requirement 1 and Requirement 2 — January 1, 2007

   Requirement 3:

   January 1, 2008 — 1st 20% compliant

   January 1, 2009 — 2nd 20% compliant

   January 1, 2010 — 3rd 20% compliant

   January 1, 2011 — 4th 20% compliant

   January 1, 2012 — 5th 20% compliant

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Criteria for reporting generating unit auxiliary loads.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.

R1.4. Periodicity and schedule of model and data verification and reporting.

R1.5. Information to be reported:

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.

R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.

R1.5.3. Verified Reactive Power of auxiliary loads.

R1.5.4. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the

Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Reactive Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to these procedures, for verification and reporting of generator gross and net Reactive Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Reactive Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous version of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2 or R1.4.

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: Procedures did not meet two or three of the following requirements: R1.1, R1.2 or R1.4.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet R1.5.1, R1.5.2, R1.5.3, or R1.5.4.

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a Generator Owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a Generator Owner's units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a Generator Owner's units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% less of a Generator Owner's units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3.	01/20/06

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2

Standard MOD-024-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
1. Number: MOD-024-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Real Power Capability	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability
3. Purpose: To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability.
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner **4.2 Facilities:** 4.2.1 Individual generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating) in a generating Facility connected at the point of interconnection at 100 kV or above.

Standard MOD-024-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
		4.2.2 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) and connected at the point of interconnection at 100 kV or above. 4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.
R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	Regional applicability is eliminated and functional entity responsibility is defined Verification, including reporting, is addressed throughout proposed Standard.	**Requirements R1 and R2** defines the verification and data reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, **Applicability,** which follows the Registry Criteria.	**4.2 Facilities:** 4.2.1 Individual generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating) in a generating Facility connected at the point of interconnection at 100 kV or above. 4.2.2 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) and connected at the point of interconnection at 100 kV or above. 4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.
R1.2. Criteria for reporting generating unit auxiliary loads.	**Requirement R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or	**R1** Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator

Standard MOD-024-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
	the basis for developing a more specialized form that provides all the auxiliary information required by the Standard.	Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	**Requirement R1** references **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be performed.	**R1** Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator.
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirement R1** references **Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	**R1** Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator.
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Real Power generating capabilities. **R1.5.2.** Real Power requirements of auxiliary loads.	**Requirement R1** references **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification. .	**R1** Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its

Standard MOD-024-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
R1.5.3. Method of verification, including date and conditions.		Planning Coordinator.
R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	**R1** Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator.
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Real Power generating capability per **R1**.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	**R1** Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator.

Standard MOD-025-1 **NERC Board Approved**	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-025-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Reactive Power Capability	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability
3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability.
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner **4.2 Facilities:** 4.2.1 Individual generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating) in a generating Facility connected at the point of interconnection at 100 kV or above. 4.2.2 Generating plant/Facility greater than 75 MVA (gross

Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		aggregate nameplate rating) and connected at the point of interconnection at 100 kV or above. 4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator’s restoration plan.
R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:	Regional applicability is eliminated and functional entity responsibility is defined Verification, including reporting, is addressed throughout proposed Standard.	**Requirements R1 and R2** defines the verification and data reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, **Applicability,** which follows the Registry Criteria.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner **4.2 Facilities:** 4.2.1 Individual generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating) in a generating Facility connected at the point of interconnection at 100 kV or above. 4.2.2 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) and connected at the point of interconnection at 100 kV or above. 4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator’s restoration plan.
R1.2. Criteria for reporting generating	**R1** references **Attachment**	**R1.** Each Generator Owner shall: [Violation Risk Factor: Lower] [Time

Standard MOD-025-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
unit auxiliary loads.	**1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard. **Attachment 1,** section 4.1 allows engineering estimates in those situations where metering to measure a reactive load is not installed.	Horizon: Long-term Planning] **R1.1.** Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **R1.2.** Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); **R1.3.** Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	**Requirements R1, and R2,** reference **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be performed.	**R1.** Each Generator Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R1.1.** Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **R1.2.** Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); **R1.3.** Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator. **R2.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R2.1.** Verify the Reactive Power capability of its synchronous

Standard MOD-025-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
		condenser units in accordance with Attachment 1 ; **R2.2.** Record the information on Attachment 2 (or on the Transmission Owner's form that contains the same information as Attachment 2) **R2.3.** Submit within 90 calendar days of the verification to its Planning Coordinator.
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirements R1, and R2,** reference **Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	**R1.** Each Generator Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R1.1.** Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **R1.2.** Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); **R1.3.** Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator. **R2.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R2.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1 ; **R2.2.** Record the information on Attachment 2 (or on the Transmission Owner's form that contains the same information as Attachment 2) **R2.3.** Submit within 90 calendar days of the verification to its Planning Coordinator.

Standard MOD-025-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
R1.5. Information to be reported: **R1.5.1.** Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capability as reported in accordance with MOD-024 Requirement 1.5.1. **R1.5.2.** Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc. **R1.5.3** Verified Reactive Power of Auxiliary loads. **R1.5.4.** Method of verification, including date and conditions.	**Requirements R1, and R2,** reference **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification. .	**R1.** Each Generator Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R1.1.** Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **R1.2.** Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); **R1.3.** Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator. **R2.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R2.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1 ; **R2.2.** Record the information on Attachment 2 (or on the Transmission Owner's form that contains the same information as Attachment 2) **R2.3.** Submit within 90 calendar days of the verification to its Planning Coordinator.
R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1** and **R2**.	**R1.** Each Generator Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R1.1.** Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **R1.2.** Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2);

Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
procedure within 30 calendar days of the approval.		**R1.3.** Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator. **R2.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R2.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1 ; **R2.2.** Record the information on Attachment 2 (or on the Transmission Owner's form that contains the same information as Attachment 2) **R2.3.** Submit within 90 calendar days of the verification to its Planning Coordinator.
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Reactive Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1 and R2**. The Transmission Owner has been added to include synchronous condensers that are under the control of the TO.	**R1.** Each Generator Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R1.1.** Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **R1.2.** Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); **R1.3.** Submit within 90 calendar days of the date the data is recorded to its Planning Coordinator. **R2.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R2.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1 ; **R2.2.** Record the information on Attachment 2 (or on the Transmission Owner's form that contains the same information as Attachment 2)

Standard MOD-025-1 NERC Board Approved	Comment	Proposed Standard MOD-025-2
		R2.3. Submit within 90 calendar days of the verification to its Planning Coordinator.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-09 Generator Verification
Two Initial Ballots and
Two Non-Binding Polls of VRFs and VSLs
Ballot Windows Open July 22 through August 1, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Initial ballots of two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Performance During Frequency & Voltage Excursions, and concurrent, non-binding polls of the associated VRFs and VSLs are open Friday, July 22, 2011 through **8 p.m. Eastern on Monday, August 1, 2011**.

Clean versions of the standards and associated implementation plans, along with redlines showing changes made since the last posting, have been posted at the project webpage at: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

Instructions for Casting Ballots and Opinions in Non-binding Polls

Members of the ballot pool associated with this project may log in and submit their votes for each standard and each non-binding poll of VRFs and VSLs (a total of four separate votes) from the following page: https://standards.nerc.net/CurrentBallots.aspx.

Special Instructions for Submitting Comments with a Ballot

Comments submitted with ballots are extremely valuable to help the drafting team revise its work. In an effort to reduce the burden on stakeholders providing comments, the drafting requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic comment form. This will ensure that stakeholders only provide a single set of comments, but have an opportunity to notify the drafting team if they have provided comments.

When submitting a ballot with comments, submit the comments through the electronic form and then simply record a "comments submitted" in the comments field of the ballot to indicate that comments were submitted.

Please note that comments submitted during the formal comment period, the ballot for the standard, and the non-binding poll for the VRFs and VSLs all use the same electronic form, and it is NOT necessary for ballot pool members to submit more than one set of comments (one during the comment period; a second with a ballot; a third with a non-binding poll).

Next Steps
The drafting team will consider all comments received, and decide whether to make additional revisions to the standards.

Background
The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2 and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Additional details are available on the project web page at: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

Standards Announcement

Project 2007-09 Generator Verification
Ballot Pool Windows Open: June 15 – July 15, 2011
Formal Comment Period Open (Two Standards): June 15 – August 1, 2011
Formal Comment Period Open (Three Standards): June 15 – July 15, 2011

Now available at: http://www.nerc.com/filez/standards/http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

The Generator Verification standard drafting team has posted five standards and their associated implementation plans for a formal comment period. Please read the following announcement carefully, because although the five standards are being posted together they are at different stages in the standards process and in order to facilitate moving forward those standards that reach consensus, the standards are being processed independently.

1. MOD-026-1 and PRC-024-1 Formal Comment Period and Ballot Pool Formation

Two of the standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Frequency and Voltage Protective Relay Settings, are posted for a 45-day formal comment period through August 1, 2011. A ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-026-1 and PRC-024-1 beginning on July 22, 2011. Please note that **separate ballot pools are being formed for each standard and non-binding poll**, and the window to join the ballot pool for each standard and each non-binding poll is open through July 15, 2011.

Ballot Pools Open through 8 a.m. EST on July 15, 2011 for MOD-026-1 and PRC-024-1 Ballots and Non-binding Polls

The Standards Committee has authorized posting these standards and their associated implementation plans for a 45-day formal comment period with an initial ballot and concurrent non-binding poll conducted during the last 10 days of that comment period. A separate ballot pool is being formed for each standard and for each non-binding poll in order to allow Registered Ballot Body members to selectively join those ballot pools in which they have an interest. To register an opinion in the non-binding poll for either standard, you must join the ballot poll for that non-binding poll. Each of the four ballot pools will be open through 8 a.m. EST on July 15, 2011.

Instructions for Joining Ballot Pools for MOD-026-1 and PRC-024-1 Ballots and Non-binding Polls

Registered Ballot Body members may join each of the ballot pools to be eligible to vote in the upcoming ballots and non-binding polls at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

- MOD-026-1 ballot bp-2007-09_MOD-026-1_in@nerc.com
- MOD-026-1 non-binding poll bp-2007-09_MOD-026-1_NB_in@nerc.com

- PRC-024-1 ballot bp-2007-09_PRC-024-1_in@nerc.com
- PRC-024-1 non-binding poll bp-2007-09_PRC-024-1_NB_in@nerc.com

Instructions for Commenting

Please use this electronic form to submit comments on MOD-026-1 and PRC-024-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

2. MOD-025-2, MOD-027-1, and PRC-019-1 Formal Comment Period

Three additional standards have been posted for a 30-day formal comment period:

- MOD-025-2 – Verification of Generator Gross and Net Reactive Power Capability
- MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- PRC-019-1 – Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

Instructions for Commenting

Please use this electronic form to submit comments on MOD-025-2, MOD-027-1, and PRC-019-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

Next Steps

Initial ballots of MOD-026-1 and PRC-024-1, and concurrent non-binding polls of the associated VRFs and VSLs, will begin on July 22, 2011 and end at 8 p.m. Eastern on Monday, August 1, 2011. Following the formal comment period for MOD-025-2, MOD-027-1, and PRC-019-1, the drafting team will consider all comments and determine whether to make changes to the standards, implementation plans, or associated VRFs and VSLs.

Background

The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2 and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions

- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Additional details are available on the project web page at http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Name (38 Responses)
Organization (38 Responses)
Group Name (27 Responses)
Lead Contact (27 Responses)
Question 1 (60 Responses)
Question 1 Comments (65 Responses)
Question 2 (59 Responses)
Question 2 Comments (65 Responses)
Question 3 (54 Responses)
Question 3 Comments (65 Responses)
Question 4 (57 Responses)
Question 4 Comments (65 Responses)
Question 5 (54 Responses)
Question 5 Comments (65 Responses)
Question 6 (50 Responses)
Question 6 Comments (65 Responses)
Question 7 (51 Responses)
Question 7 Comments (65 Responses)
Question 8 (47 Responses)
Question 8 Comments (65 Responses)
Question 9 (42 Responses)
Question 9 Comments (65 Responses)
Question 10 (54 Responses)
Question 10 Comments (65 Responses)
Question 11 (53 Responses)
Question 11 Comments (65 Responses)
Question 12 (50 Responses)
Question 12 Comments (65 Responses)
Question 13 (49 Responses)
Question 13 Comments (65 Responses)
Question 14 (56 Responses)
Question 14 Comments (65 Responses)
Question 1 (46 Responses)
Question 1 Comments (65 Responses)
Question 2 (46 Responses)
Question 2 Comments (65 Responses)
Question 3 (43 Responses)
Question 3 Comments (65 Responses)
Question 4 (44 Responses)
Question 4 Comments (65 Responses)
Question 5 (47 Responses)
Question 5 Comments (65 Responses)
Question 6 (47 Responses)
Question 6 Comments (65 Responses)
Question 1 (43 Responses)
Question 1 Comments (65 Responses)
Question 2 (43 Responses)
Question 2 Comments (65 Responses)
Question 3 (40 Responses)
Question 3 Comments (65 Responses)
Question 4 (47 Responses)
Question 4 Comments (65 Responses)
Question 5 (45 Responses)
Question 5 Comments (65 Responses)
Question 6 (39 Responses)
Question 6 Comments (65 Responses)
Question 7 (47 Responses)
Question 7 Comments (65 Responses)

Question 8 (43 Responses)
Question 8 Comments (65 Responses)
Question 9 (45 Responses)
Question 9 Comments (65 Responses)

Group
LG&E and KU Energy
Brent Ingebrigtson
No
Either the Planning Authority of the Transmission Planner are the more likely entity to submit data rather than the Transmission Owner as indicted in R2.3
GO’s typically correct to back pressure. Any other adjustments should be performed by Transmission Operator
No
Blackstart unit testing is covered in he EOP standards, and should not be included in the MOD standards. Most of these are smaller units that don’t have much impact on the BES but are important because they are blackstart—not for the VARs.
The addition of the lagging and leading at (2); the expected minimum Real Power output are new points to test from the existing version of MOD-025. This will eventually double the testing window (at a minimum)
Group
Northeast Power Coordinating Council
Guy Zito
Yes

No
The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Yes
Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
No
Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Yes
Yes
No
Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.
Yes
Yes
Yes
Yes
No
No
No
No
No

A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
No
Can't generators be operated as synchronous condensers if needed?
No
No
Yes
In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
No
This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
No
Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Yes
Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage]. Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
No
Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.
Yes
Yes
No
The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
No
Yes
Related to the "Examples of Coordination", the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve

is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Group
Imperial Irrigation District (IID)
Sammy Alcaraz
Yes
Yes
Yes
THE REAL POWER DATA OBTAINED FROM GENERATORS IS BASED ON AMBIENT TEMPERATURE AND ADDITIONAL ENVIRONMENTAL AND SYSTEMATIC CONDITIONS. BECAUSE OF THIS REASON, OBTAINING A CORRECTION FACTOR CORRESPONDING SOLELY TO THE AMBIENT TEMPERATURE FOR CALCULATION OF THE REAL POWER WILL NOT BE AN EFFECTIVE APPROACH. IN ADDITION, DUE TO SEVERAL PARAMETERS AS A FUNCTION OF THE REAL POWER AND THE TEMPERATURE, CALCULATION OF AN ACCURATE CORRECTON FACTOR WOULD BE SOMEWHAT DIFFICULT AND COSTLY AS IT MAY REQUIRE SEVERAL GENERATOR TESTING.
Yes
Yes
WE BELIEVE THAT FOUR POINTS IS SUBSTANTIAL INFORMATION FOR STRAIGHT LINE APPROXIMATION AS OVER-EXCITED (LAGGING) AND UNDER-EXCITED (LEADING) REACTIVE CAPABILITY AT RATED REAL POWER WOULD SOLELY BE A SUFFICIENT DATA FOR THIS PURPOSE.
Yes
Yes
Yes
THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Yes
THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Yes
Yes
No
No
No
No
Yes
Yes

No
No
Yes
IT WOULD BE EFFECTIVE IF SDT WOULD CONSIDER PROVIDING A DETAILED EXAMPLE OF DYNAMIC MODELS, GRAPHS, AND INFORMATION REQUIRED AS PART OF THIS STANDARD.
Yes
Yes
No
These devices are covered already under the VAR standards.
Yes
Yes
Yes
Yes
No
No
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
No
SCE&G believes that the Transmission Planner (TP) should receive this information, consistent with the current version of the standard.
Yes
The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
No
The verification of sisters units on an alternating basis should be allowed by the standard.
Yes
Yes
Yes
Yes

No
The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits.
No
No
Yes
If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners.
No
Yes
Yes
No
No
Yes
How are sister units to be handled? Do they all need to be tested individually. Also, are all the units counted individually when calculating the percent of units in the implementation schedule?
Yes
Yes
Yes
No
There seems to be a mistake on the Implementation Plan versus the Standard. The implementation plan states two years for the first 20% of applicable units and the standard states one year. Please clarify this inconsistency.
Yes
No
No
Yes
In regards to Measure 1 it should be clarified that only the latest coordination review will be needed for the first 5 years after the standard is implemented and only after 10 years will the entity be required to show both latest and prior evidence of compliance for 100 % of the applicable units. As stated, it looks like the standard would require the entity to verify the existence of coordination twice on 20% of the applicable units in the first year to show evidence of a latest and prior coordination for those units. If an entity were to be audited 3 years after the effective date of the standard, they would have to show coordination of 60% of the applicable units and should not be required to show a prior documented coordination since a 5 year interval would place the prior coordination possibly before the effective date of the standard. This would also apply in the situation of a newly built

applicable unit in which there would be no prior evidence available; only the latest.
Group
Westar Energy
Bo Jones
Yes
No
We agree data should be submitted to the Transmission Planner as written in the draft of the standard.
No
We believe data should be submitted to the Transmission Planner as written in the draft of the standard.
Yes
We propose that language be added to reference the Compliance Registry to ensure that as the Registry changes the appropriate applicability is followed.
Yes
Yes
No
We suggest that the SDT considering adding clarifying language around “as soon as a limit is encountered.” The current language is ambiguous.
Yes
Yes
We agree with the 50 MVA limit, however the standard does not currently address this limit.
Yes
Yes
Yes
The SPP Criteria requires that the testing period should be 15 minutes rather than the 1 hour listed in the standard.
No
No
No
We suggest for consistency with the other standards in this project that this standard also reference the limits used in the Compliance Registry.
Yes
Yes
No
No
No

Yes
Yes
In the standard the applicability for synchronous condensers is > 20 MVA for an individual unit. Additional language should be added to the standard to address the applicability for generating units/facilities.
Yes
Currently the requirements do not address variable static reactive resources located at asynchronous generating facilities as the question states. If the intent is for the standard to apply to variable static reactive resources located at asynchronous generating facilities, we propose language be added to the standard to address these resources. Yes, we do see a reliability need for including variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites. We propose that language be included to address the limit on the size of these types of facilities.
Yes
No
We would recommend the following implementation schedule: 20% - 2 years after regulatory approval 40% - 3 years after regulatory approval 60% - 4 years after regulatory approval 80% - 5 years after regulatory approval 100% - 6 years after regulatory approval
Yes
Examples for older units, where the information in the current examples are not readily available, could be included.
Yes
No
No
Group
IRC Standards Review Committee (joint comments)
Albert DiCaprio
No
It is not a matter of whether the requirements for real power verification is in one numbered standard and reactive verification is in another numbered standard, the important point is that the requirements be clear and separate. The posted standard fails that test by combining two requirements into one. It may look cleaner writing the two together; the problem is with the fact that such a format has the potential to needlessly risk getting some data when the other data is NOT available. If an asset owner could provide real data but not reactive data, the standard as written would incent the owner from providing either data (why waste a test when the owner knows it will be non-compliant anyway? By separating the two actions, the owner would be compliant with one and non-compliant with the other requirement – but the planner would have at least half the information.
No
MOD-025 is a requirement on owners to verify data, nowhere does the requirement state who the data goes to. Of course the owner is NOT the appropriate entity to send the data to since they are the ones that are responsible for generating the information. This standard has many issues related to who gets what data and why. There is no requirement to have the data in the first place. The standard would be better to require a planning entity to request the data that that entity needs to do its mandated functions. Once the planner asks for the data, then the owner can provide / verify the information being asked for. The SDT has rejected the comments that other standards already provide this information. The SDT has parsed the terms “capability” and “rating”. However, the NERC Glossary defines Rating as strictly a transmission line term, and the word capability is not defined. Capability does show up within other definitions related to Transfers and other transmission terms.

The SDT is asked to review their findings in light of the above, and in light of the FAC and TOP standards purposes. The TOP standard has developed the flexible approach of having an entity ask for the data it needs, and for the receiver of the request to provide the needed information. This approach eliminates the idea of a common requirement for all planners (whether or not they want the data elements in the posted Attachment 2). Our proposal is to have a requirement (if it does not already exist) mandating entities asks for what they want, and a separate requirement for the receivers to provide just that data. If the revised standard is written in that fashion than the new MOD-025 COULD replace the old MOD-024 because there would be no need to specify reactive data from real data, because the entities who are asking for the data will do that for you. Editorial: (1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”, we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.”, or be revised to: “To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs. (1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator’s real power capability to reflect a difference in ambient temperature. If anyone, it should be the Generator Owner. (2) Reporting the ambient temperature is unnecessary since it is only one of the many factors that could affect the real power output of a generator. Adjusting the real power capability for a different ambient temperature does not really provide a more accurate value, and can be misleading. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome, and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
No

See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Yes
No
There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Yes
No
We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: “Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:” We interpret that the “IT” refers to the operational data. As such, we do not understand the “within 20% of the expected value”. Does it mean the generator’s real power output during the period from which operational data was collected must be within 20% of the generator’s declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity. As written, we are unable to comment on the acceptability of the 20%.
No
No
Yes
The proposed MOD-025-2 standard appears to violate many conventions, such as: o The use of Attachments for mandating requirements o The combinations of different actions in the same requirement o The mandating of specific formats

Does this SDT really believe a standard will "prevent" trippings due to mis-coordination?
Individual
Edward Cambridge
APS
being intentionally left blank (no answer to be provided)
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Group
Pepco Holdings Inc Affiliates
David Thorne
Yes
No
The standard in Sec B-R1.3 and R2.3 state to submit the data to the TP not the TO. The TP is the appropriate entity. However, the TOP and the TOP also have need of the data. Should dissemination to these entities be covered in the requirements also?
Yes

The ambient temp and correction factor should be provided to the TP with all the data as stated in Question 2.
Yes
Yes
However, based on the requirements and measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only apply to Transmission Owners that own synchronous condensers. If that is the case, Section A- 4.1.2 should be re-written as follows: “Transmission Owner that owns a synchronous condenser.” This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined.
Yes
Question 9 mentions that a threshold was proposed by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
Yes
“Staged” vs “operational” verification should be defined. In Attachment 1, are sections 2 and 5.2 consistent? That is should the % value be the same?
No
20% “appears” to be a large variance. The DT should explain the justification for 20%. 5% or 10% would seem more reasonable, especially for large units.
Yes
Should Attachment 1 Sec 5 be added to the standard list of requirements instead of part of the attachment? It appears that this section is more than just additional details on verification and reporting. In the project background information it is stated “..If regions have generating units that are connected at under 100 kV that are important to the reliability of the system due to some local consideration, then the region has the authority to require that those units be verified if they so choose.” This capability should be noted directly in the standard.
Yes
Yes
Question #2 mentions that a threshold was chosen by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
No
Question #3 indicated that as currently drafted the standard applies to variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites). This is either

specifically mentioned, or inferred, within the language of the June 15, 2011 Draft 2 standard. Regarding the question of a reliability need for including variable static reactive resources (e.g. static Var compensators) that are not located at generating sites in this standard, the answer is no. We see no need to make the standard applicable to Static Var Compensators (SVC's), whether they are located at generating sites, or remote from generating sites. An SVC is merely a thyristor switched / controlled capacitor or reactor. Maximum and minimum output is controlled by the firing controls to the thyristor, and is limited by the size of the installed shunt capacitor / reactor banks. When the thyristor is switched off there is no output. As the firing angle is increased toward the full on position the reactive output is increased until the full value of the shunt capacitor bank, or reactor bank, is reached. Protective devices and settings on the shunt capacitor bank and reactor bank within the SVC are typical of those employed on fixed banks. The control system merely provides a means to adjust the output between zero and full bank rating. As in the case of fixed banks, SVC protective devices are set assuming the full bank is in service. Therefore, if fixed shunt reactive banks are not subject to the standard, which they should not be, then SVC's should not be either. Synchronous machines, however, are a different story entirely. The quantity of reactive power produced by, or drawn into, the machine is a function of the machine field current. In an under-excited condition the unit may loose synchronism, or trip via loss of field protection, unless the voltage regulator (min. excitation limiter) is properly set and coordinated with the machine's capability and protective devices. Similarly, excessive Var output and / or terminal overvoltage caused by over-excitation of the field can result in equipment damage, or unit tripping, unless the voltage regulator is properly set and coordinated with the machine's capability and protective devices.
Yes
Yes
Yes
No
Yes
Based on the Requirements and Measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only apply to Transmission Owners that own synchronous condensers. If that is the case, Section A- 4.1.2 should be re-written as follows: "Transmission Owner that owns a synchronous condenser." This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined. Do the requirements in this new standard overlap or duplicative with PRC-001 R3 and R5?
Individual
Brad Haralson
Associated Electric Cooperative, Inc.
No
Real power verification is typically done using historical operating data because units commonly operate at full real power capability. Reactive power verification will most likely not be done using historical operating data. This standard implies that these verifications will be done at the same time. Applicable standards should allow for real and reactive verifications at different times.
No
The TP or PA seems more appropriate.
No
There is no simple correction factor that can be provided that will allow correction to other ambient temperatures. If necessary, a special request could be made to the GO/GOP for correction to another ambient temperature.
No

The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERCs current MOD-025 regional criteria). Independent verification of essentially identical units should not be required.
No
We don't agree that four points are needed for baseload units, since they are rarely expected to operate at or near Pmin. In addition to nuclear units, baseload units should be exempt from reactive capability verification at Pmin.
Yes
Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method.
Yes
We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR requirements when operating at low system load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
Yes
No
It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify more appropriate generating unit reactive capabilities that are needed to ensure that planning entities have accurate generator data when assessing BES reliability. MOD-025-2 should not focus solely upon operational testing to determine capabilities used for planning models, because experience has shown that testing does not provide appropriate reactive power capabilities. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed.
No
No
Yes
1) We agree with the stated purpose of this standard however we don't believe that this standard, as written, meets the intent related to reactive capabilities. We have already spent significant time, effort and money to perform reactive capability testing, and the test results provide little value toward establishing appropriate capabilities for planning purposes. Additionally, this testing puts our equipment and the BES at risk. It appears that this standard will make us repeat this effort with additional requirements for reactive capability testing at Pmin. 2) This requirement will require units

that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 3) The standard needs to allow the inclusion of engineering analysis to supplement or replace testing when appropriate (see comments to question #10). 4) Instead of the periodic requirements, there needs to be a change based validation requirement. If a plant is materially changed (such as significant equipment changes or performance degredation), there needs to be a new validation done. 5) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 6) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 7) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 8) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 9) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 10) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 11) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 12) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 13) Revise attachement 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 14) Note that the standard is only applicable to the GO/GOP, but needs involvement from the TO/TP/TOP to adequately complete a validation. Thus the standard needs to address the responsibilites of those entities for it to adequately address the issue of model validation. It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achiving the reliablity purpose intended. 15) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creats a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators.
No
Yes
Yes
No
No
Yes
1) Item 2.1.1 should be reworded: ".......model verification activities including the on-line RECORDED response compared to the MODEL'S SIMULATED response....." 2) It is anticipated that many GO/GOP's may not have industry experience with modeling concepts and model verification techniques. It may be beneficial to provide an appendix for reference that basically describes the anticipated mechanics of how the verification is performed. This may help provide consistency for the verification process.
Yes

Yes
Yes
Yes
Yes
Yes
No
No
Individual
Dan Roethemeyer
Dynegy Inc.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
No
Yes

Yes
No
No
Yes
1) In R2.1.1 it is not clear if the “recorded” response refers to the model response. Consider rewording this requirement to make clear the meaning of “recorded”. 2.) Attachment 1 seems to give two options for periodicity of verifying the model frequency control functions for existing generators. One option is to record data for a BES frequency excursion during a ten year calendar period. A second option is to record such data after the ten year period if a suitable BES frequency excursion does not occur. Does this mean existing generators can wait indefinitely for a suitable frequency excursion to verify the model response?
Yes
Yes
Yes
No
Some of the requested data will reside in places not familiar to smaller entities and may require the use of consultants. The SDT may want to consider giving 2 years until the first 20% compliance level is reached because it will take time to set up a program.
Yes
No
No
Group
NERC System Protection and Control Subcommittee
Jonathan Sykes, Chair

Yes
No
The SPCS notes that the posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. The SPCS agrees with the 20 MVA threshold in the posted standard.
Yes
Devices such as Static Var Compensators and STATCOMs have equipment limitations, control systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser.
Yes
Yes
No
The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency.
Yes
No
Yes
Requirement R1: The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the generating unit, such as the list in Section G. Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions. Requirement R1, part 1.1.2: The word "check" is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as "Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment." Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project the Generator Owner should be required to verify coordination prior to placing the revised equipment or settings in-service. The SSSL derivation should consider the impact of system strength (e.g., strongest transmission line source out-of-service), generation saturation, and AVR status to assure an appropriately conservative limit. Implementing a UEL based on the steady-state stability limit may prevent under-excited operation, which would otherwise be stable and useful in managing system conditions (such as during system restoration activities or in lightly-loaded areas that need to sink reactive power to control voltage or synchronizing a generator to a long line). Where the Generator Owner and Transmission Owner are separate entities, there is difficulty for the Generator Owner to obtain system impedance information and keep it up to date as the transmission system may be re-configured during on-going operations; this information is necessary to represent the SSSL. The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with

controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.
Individual
Greg Campoli
New York Independent System Operator
Yes
No
In section B, R1.3, results are required to be submitted to the Transmission Planner. The NYISO agrees with R1.3.
No
Temperature correction shall be performed as required by the Transmission Operator. The NYISO requires ambient temperature data only for Real Power Tests for combined cycle, combustion, and turbine units.
Yes
No
There is no value to performing the lagging testing at minimum real power loading and leading test at maximum power. The testing requirement should be changed to two test points. One test for an hour to verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner; a second test to verify under-excited capability (leading) at the real power level specified by the Transmission Operator or the Transmission Planner.
Yes
No
Testing requirements for reactive capability at minimum real power output should be removed. These tests are of no value and lead to system limit concerns. The testing requirement should be changed to two test points. One test for an hour to verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner. A second test to verify under-excited capability (leading) at the real power level specified by the Transmission Operator or the Transmission Planner.
Yes
No
100 MVA is a more appropriate limit.
Yes
No
What determines the expected value to be within 20% of?
No
In the NPCC region Directory 9 and 10 were written to meet the original obligations of MOD-024 and MOD-025. These directories are more specific or more stringent than MOD-025-2.
No
Yes
Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within its area. Additional NYISO Comments not addressed above for MOD-25-2 Under A. Introduction • Section 4 – Transmission Planner should be added under Functional Entities • Section 5.1.1 through 5.1.5 and 5.2.1 through

5.2.5 – These requirements should clarify that the Transmission owner requirement is for units that the Transmission owner owns and not for the generators in the Transmission Owners area. Under B. Requirements • Section 1.3 – The requirement should either be up to 225 days after the test or 60 days after the end of the test period. Attachment 1 – Verification of Generator Real and Reactive Power Capability • Section 1 – There should be some provision for allowing the verification results from small, electrically identical units at the same location to apply to other units in the group. • Section 2.1 – It is not practical to determine reactive power at rated gross Real Power capability. The requirement that ninety percent of wind turbines or photovoltaic inverters be online during verification of reactive power should be removed. • Section 2.2 – This verification is not needed. • Section 2.4 - Please clarify the definition of “limit”. • Section 3.2 - Please clarify the definition of “voltage schedule”. • Section 3.3 – This data is not needed. • Section 3.4 - Ambient air temperature is not needed for reactive power test results. It is only necessary for certain generators in Real Power tests (combined cycle, combustion and turbine). • Section 4 – The diagram is not needed. • Section 4.1 – For the NYISO, Real Power verifications are conservatively measured as Net output, so no auxiliary loads are required to be reported. Attachment 2 • Attachment 2 requires an unnecessary level of detail for “Data Type” to be recorded and collected; only gross MVAR, auxiliary reactive power and Net MW readings are required. • What is meant by “MVAR values were adjusted to rate generator voltage”?
Group
Southern Company
Antonio Grayson
Yes
No
The TP or the PC is the entity who needs the data, not the TO. R1.3 and R2.3 specifies that the TP be given this data.
No
The verification data is required by R1.3 and R2.3 to be given to the TP, not the TO. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.
No
We believe that Section 4 Applicability for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. However, for plants with a gross aggregate nameplate rating ≥ 100, we question the need to perform verification for individual units as small as 20 MVA. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for verification of units as small as 20MVA needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their

criticality to the system seems to be inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1.
No
We agree that four points are sufficient to provide a straight line approximation over a unit's operating range. However, we strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." Paragraph 1321 of the FERC Order states, "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit’s real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit’s real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." These statements indicate the Commission is seeking further guidance from the industry. Based on this, we have the following recommendations. First, we believe 2.2 of Attachment 1 to the standard should exempt all base load units, not just nuclear units, from verification of reactive capability throughout the full MW range. There are other units the industry should be able to justify exempting based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) that prevent operation at minimum load. Second, we suggest that an evaluation be made on a small subset of units that could then be used to respond to the question raised by FERC. Our experience indicates that a unit will typically be capable of delivering or absorbing a comparable amount of reactive power to/from the grid at minimum load when compared to full load. The industry as a whole does not need to perform the verification at multiple points on 100% of the units to respond to an open question from FERC. Third, for units where verification of multiple points are needed, the analytical approach to verification we discuss in our responses to Questions 10, 11, and 14 serves this purpose very well.
Yes
Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Yes
We believe that the minimum load, it will be difficult for a unit to produce Vars because the system usually has minimum VAR output requirements from generators when the generators are operating at minimum load. Therfore, we believe verification of Vars out at minimum load will not provide the data that transmission planning is seeking and, therfore, this requirement is not necessary. See our response to Question 5 for additional discussion on verification at minimum load.
No
No
This MVA size does not agree with that found in the Applicability section 4.2.1 (20 MVA). As previously stated, we feel that the size of an individual unit that is significant in the Eastern Interconnection is 100 MVA.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). Reliance on data from testing or operations alone will result in understated reactive capabilities for planning purposes. To provide these alternative methods of establishing P&Q capabilities for each applicable facility, it is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or Attachment 3 (by engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is

noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
The "expected value" is not clearly identified, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the D curve for lagging Vars, we believe this is not a realistic expectation because operational data for most generating units does not approach 80% of the D curve value in normal operating conditions or even in staged testing based on our experience. A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed to be an alternative method for verifying the unit capability, the 20% tolerance given above is not needed. See our Comment 2 under Question 14 for additional discussion on the verification methods.
No
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be run for testing. Please consider a provision for excluding these requirements for units that do not regularly run unless verification using engineering analysis is allowed. 2) Each of the methods of verification proposed have merits and deficiencies. For staged testing, there exists the risk of tripping a unit during testing. System conditions which allow for the maximum reactive power output production/absorption are extreme system voltage conditions - precisely where it is undesirable to perform such testing or trip a unit. Staged testing or verification using operational data during normal system voltage conditions will result in reactive limits constrainted by system conditions (not representative of the actual unit capabilities for extreme voltage conditions when the reserve Var capabilities are needed most). Staged testing may, however, reveal unknown thermal or mechanical problems which, while are good to know, are maintenance related and are not the primary objective of the standard which is verification of reactive capability for use in planning models (Long Term Planning Horizon). But, if system constraints during staged testing do not permit a unit to reach the reactive limits the unit could reach during extreme system votlage conditions, one could argue the results of the test are inconclusive in terms of meeting the reliability objective of the standard. Our experience has shown that unit reactive limits for extreme voltage conditions (when the reserve Var capabilities are needed most) can best be determined using engineering analysis. It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC Regional Criteria for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The test interval and new unit test requirement described in Attachment 1, part 5 should be included in the main standard requirement section rather than in the staged test details. However, we believe re-verification every 5 years is too frequent. We agree that re-verification is appropriate for significant changes that impact the real or reactive capabilty by more than 10%, but we question the six month criteria. For the Long Term Planning Horizon, one year would be more appropriate. 4) In R1.2 and R2.2 the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changin R1.2 anf R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to

read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 11) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP (> 30 days late).
No
1) We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action. 2) It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy.
Yes
Yes
No
No
Yes
1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don’t match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) In Requirement R4, it is unclear how an entity could revise model data without performing a model verification - (the requirement is written to either revise model data or plan to perform model verification) 8) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. Those items that need correcting include: 8a) The "Facility" column entries need to better describe the conditions that are being detailed in the "Condition" column. Can some additional words better describe the each row? [for example, the row 2 could have the title 1-existing unit, no sister unit exceptions; row 3 could have the title 2-existing unit, sister unit exception applies, etc.] 8b) The use of "exceptions" in the Draft 1, row 2 is not defined and it is unclear what exceptions may apply. 8c) Can the third AND element of the Condition described in row 2 be written more simply by beginning "While the unit is operating in a frequency responsive mode and is subjected to at least one BES frequency excursion as specified in Criteria 1 above." This change could be used in multiple entries of

this table to simply the reading and understanding. 8d) For row 3 (with exceptions row), we suggest eliminating the requirement for the same physical location being true for allow "sisterhood" - an entity is likely to own multiple units at different physical locations which are identical. 8e) Row 5 contains "new excitation control system equipment" - shouldn't this be "new governor/load control equipment"? 8f) Row 7 contains "Excitation control system model" rather than "Gov/Load control model"
Yes
No
We feel that this standard is not applicable for solar facilities. For other facilities, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit, 15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units ≤ 75MVA may be identified by a transmission entity as critical for BES reliability. Thus, the standard could include requirements applicable to such units where identified by a tranmission entity as critical for BES reliability.
Yes
Yes
Yes
No
Only the last two documentation sets are needed to prove the intervals are being met. ALL previous sets are not necessary. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
No
Yes
1) The last sentence of Measure M1 is not needed. There is no need to require evidence of the change implemetation, only coordination verification is needed. The requirement for documentation of change identification or implementation is not part of Requirement R1. 2) In several places in the posting documents there is a descrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 3) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 4) Section 5.2.5 is missing from effective date in the draft standard.
Individual
Samuel Reed
Tri-State Generation and Transmission, In.
Yes
Yes
The standard also calls for the data to be submitted to the Transmission Planner, so this question seems ambiguous.
No

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
No
Yes
Yes
No
No
No
Yes
Yes
The standard seems to indicate 20mva instead of the stated 50mva.
No
The standard name indicates it applies to generating sites.
Yes
Yes
Yes
Yes

No
No
Individual
Russell A. Noble
Cowlitz County PUD
Yes
Combination of closely related standards simplifies compliance program development, and is welcome.
No
Not all Transmission Owners have a complete system view of the BES, let alone modeling software. The standard as written specifies the Transmission Planner, and so the question appears to be in error. Following the purpose statement of the standard, the Planning Coordinator (formerly Planning Authority) might also need the data along with the Transmission Planner. To further complicate the matter, in WECC CUG meetings it has been brought up that entities are experiencing difficulty in identifying their Planning Coordinator and Transmission Planner. Such entities have been rebuffed when approaching the obvious candidates. Therefore, Cowlitz suggests that a mechanism must be devised such that Generator Owners will not left in a compliance quandary in their endeavors to identify the appropriate planner(s).
Yes
As long as correction factors may be documented from normal run history, this would not be burdensome to produce. As currently written, MOD-0025-2 appears to allow the Generator Owner to make a judgment call on whether ambient air temperature plays a significant role in generation capacity. If this is the case, then the report form should have a specific question: Is ambient air temperature correction factor applicable? ______ If yes, include in remarks below correction factors for different temperatures. Also, water coolant temperature may play a greater role. A quick passing hot or cool day during testing may not have any effect on the water coolant temperature. Where water temperature has a greater impact on capability, seasonal trends may be of greater significance. Finally, there is no criterion stipulated to define when ambient temperature correction factors are significant and should be provided. Cowlitz suggests that ambient temperature should only be considered significant if it affects Real or Reactive Power capability more than 10% between the lowest and highest expected ambient temperature extremes.
No
The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Cowlitz is not convinced that the Standard be applicable to the compliance registry of Generator Owners. For example, an entity owning a single small 500 KVA generation plant currently is exempt from registration; however it may own a transmission protection system protecting a BES element from a fault originating on the high side of the step up transformer. Therefore it should register as it is material to the reliability of the bulk power system. From the extensive reference of 20 MVA and 75 MVA in the Standard from the Compliance Registry Criteria, it appears that the SDT would not see a need for the 500 KVA generation plant to verify its capability. Further, pointing to the Compliance Registry Criteria’s generator MVA name plate ratings is also questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. After reviewing the Field Test Results, Cowlitz finds that WECC set the line at 10 MVA and SERC recommended 75 MVA with no substantiating arguments. Also noted in the Field Test Results was a

problem in getting the dynamic models to return data results that agreed with actual events. With the Field Test Results dated in 2007, Cowlitz is unsure on the current accuracy of dynamic model predictions. However, if models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Looking over the data requirements of MOD-25, Cowlitz can see that there will be considerable consultant cost – $25,000 – to comply. Using the Compliance Registry Criteria for applicability is not acceptable. Unwarranted compliance efforts will reduce overall reliability results. Cowlitz recommends the SDT consult with Planning Coordinators (Planning Authorities) and Transmission Planners on the current status of modeling accuracy and request documentation for generation that can be ignored. Also, it may be permissible for smaller generation to simply report seasonal historical Real and Reactive Power output.
No
Cowlitz answers “no” in that the question does not address if the data is truly going to be used. The SDT should confer with Transmission Planners requesting specifically how they will implement such data and if it will result in better modeling results. Data collection that will not be used is wasted compliance effort. FERC also seems to be confused as to the purpose of the Standard when it states “[t]he capability of generators to produce reactive power is essential for real-time analysis” rather than system modeling and planning. Based on this, should the reactive capability data also be sent to the Balancing Authority? If the SDT has technical foundation to refute FERC’s directive then it should be communicated. The Standard can be written as FERC demands, but with a recommendation that the requirement be removed.
No
Cowlitz suggests that “rated” be replaced with “normal expected maximum” in requirement 2.1 and “maximum” in requirement 2.3; although the footnote makes the intent clear, there is no need to complicate the reading of the Attachment and effectively redefine the normal understanding of the word rating. As far as running the test at least one hour, this commenter is not sure how quickly a unit achieves thermal stability. Again, Cowlitz questions if the data will be used and its actual contribution to improved modeling and future planning.
No
Cowlitz at this time has insufficient information to formulate an opinion, but at the same time is skeptical of the reliability benefit being great enough to justify the cost of obtaining this data.
Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Yes
Operational data will always be the preferred method of obtaining verification; however Cowlitz can’t see how this would be possible for obtaining the reactive capabilities as prescribed. This will require costly and burdensome staged testing.
Yes
No
No
Yes
As already stated, Cowlitz questions the reliability benefit of the extensive reactive capability requirements and is currently consulting with Transmission Planners if such extensive data will actually be beneficial in their modeling efforts. It may be better to require data that must be verified though staged testing only after request by the Transmission Planner with a reasonable time frame to obtain the data.
No
Yes

Yes
No
No
No
Cowlitz has no opinion.
No
The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Using the Compliance Registry Criteria’s generator MVA name plate ratings to assign applicability of the Standard is questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. If models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Further, the unit versus plant MVA criteria is illogical. If the BES can withstand the loss of a 75 MVA plant, then logically it will withstand the loss of a 20 MVA unit. Cowlitz believes that after the appropriate study is completed, the applicability line should be somewhere in the range of a verified nominal plant or unit output of 100 to 200 MVA. Last of all, applicability should be assigned to BES generation when it has been defined.
Yes
But not at the 20/75 MVA name plate criteria. First the applicability should be tied to expected maximum MVA output. Second, the MVA basis should be established from a modeling study. Ultimately, the applicability should only include plants that are members of the BES once this has been defined.
Yes
Yes
For Cowlitz, this would be acceptable. However, Cowlitz only owns a few generation plants. We must defer to those who own many plants.
Yes
Cowlitz needs to confer with its consultant to form a more informed opinion. However, it appears to be reasonable.
Yes
No
Yes
Cowlitz understands the difficulty the SDT is under. Although the base line of applicability is in question, this Standard is justifiable and will not present too great a burden to comply with.
Individual
Alice Ireland
Xcel Energy

Yes
Yes
No
Yes
Yes
No
Southwestern Power Pool testing criteria specifies a 15 minute hold point and WECC requires holding until the temperatures are stable, which has always been less than one hour. We believe one hour is excessively long, and instead recommend a 15 minute verification time.
Yes
Yes
Yes
There is a discrepancy between this question and the size limit in the draft standard (20 MVA). We believe 50 MVA is the better value.
Yes
Yes
No
No
Yes
It is not clear in the standard if a separate load flow report (Attachment 1) is required for each point of verification, or only for the maximum load, maximum lagging reactive point. Please clarify in the standard.
No
Yes
Yes
condensers have no effect on system frequency, they are there for voltage support. We agree they should not be in MOD-027-1.
No
No
No
Yes
Yes

There is a discrepancy between the question and the 20 MVA size limit for synchronous condensers in the draft standard. We believe 50 MVA is the better value.
No
These units are not tested under the proposed MOD-025-2, so should not be included in PRC-019-1.
Yes
Yes
Yes
Yes
No
No
Group
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)
Carol Gerou
Yes
No
The standard states that the data be submitted to the Transmission Planner and we agree with that approach.
No
We recommend that in Item 3.4 of Attachment 1 the wording be changed from “to allow the Transmission Owner” to “to allow the Transmission Planner”. We support the position that the ambient temperature at the end of the verification period and the correction factor should be provided to the Transmission Planner so that the Transmission Planner can adjust the verification results to the ambient temperature that is appropriate for its system planning assessments.
No
There may be generating units or facilities that are included or excluded as BES elements either by the latest BES definition or the latest BES exception procedure that differ from 4.2.1 and 4.2.2. So we recommend adding anItem 4.2.4 to the Applicability section that states, “Generating facility, generating unit or synchronous condenser that are designated as a BES Element according to the BES definition or BES exception procedure.”
Yes
Yes
Yes
Yes
Yes
Yes
Yes

No
No
Yes
Please consider the following comments: Attachment 1, Item 2 – Add the adjective “gross” to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. Attachment 1, Item 2 – Modify the wording of “with all auxiliary equipment needed for expected normal operation” to “with all auxiliary and voltage regulation equipment, such as reactive power compensation, needed for expected normal operation and voltage regulation” to assure that any reactive power compensation equipment (e.g. capacitor banks, SVCs, STATCOMs) are not overlooked and omitted from the verification data. This added text is particularly needed for wind generation situations. Attachment 1, Item 2 – We would prefer the acceptable verification with operational data to be 10%, rather than 20%. Attachment 1, Item 2 – Expand the text of “expected value” to “expected maximum gross Real and Reactive Power Generator capability values” to add more clarity. Attachment 1, Item 2.1 – Add the adjective “gross” to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. Attachment 1, Item 2.1 – Replace the wording “at rated gross Real Power capability” with “at the generating unit’s normal expected maximum Real Power capability” and drop the footnote reference. Attachment 1, Item 2.2 – Add the adjective “gross” to the Real Power and Reactive Power references for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. Attachment 1, Item 2.4 – We think that both “2.1 and 2.2” should be referenced for the over-excited data. If this is incorrect, then please explain why 2.1 should be omitted. Attachment 1, Item 2.6 – Add an Item 2.6 of “Record the generator step up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer”. This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements were taken. We are aware that this oversight has already occurred several times. [Add Point “F” (pointing to the generator step up transformer) to the Verification Information Reporting Form in Attachment 2 to accommodate and remind the Generator Owner or Transmission Owner to record these losses, when it is needed.] Attachment 1, Item 3.4 – Correct the functional entity reference from “Transmission Owner” to “Transmission Planner”. Revise the wording to allow the Generator Owner or Transmission Owner to report, “The ambient air temperature and/or ambient water temperature at the end of the verification period”. [Require that the ‘basis’ ambient air temperature and/or ambient water temperature associated with the reported gross generator Real Power capabilities be stated on the Verification Information Reporting Form along with a correction factor if any, to allow the Transmission Planner to correct the Real Power capability to different ambient temperatures, if needed.] Attachment 1, Item 3.7 – Add an Item 3.7 of “The GSU transformer losses if the verification measurements were taken from the high side of the GSU transformer.” This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements are taken”. Attachment 1, Item 5.3 – Add revise the wording, “within one year of their commercial operation” to “within one year of their commercial operation or as scheduled by the applicable Transmission Planner” to allow the exception of an earlier or later due date when it may be appropriate and agreed to be the affected Transmission Planner. Attachment 2, Item A – Add a note that the individual unit values should be reported separately whenever the verification measurements were taken at the individual unit. In most cases, the individual units are modeled separately (including compound units) in the power flow cases and the loss of individual units are simulated in system planning assessments. So, if the verification data was collected in a manner that would allow individual unit power capability verification, then the reporting form should not direct the Generator Owner or Transmission Owner to mask this information. Attachment 2, Item F – As noted above, add a Point “F” (pointing to the generator step up transformer) to the Verification Information Reporting Form to refer to the GSU transformer losses. Also add a Point “F” row to the data table with entries that indicate to provide the GSU transformer MW and MVAR losses when the verification data was based on measurements that were taken from the high side of the GSU transformer. Otherwise, GOs and TOs that base verification values on measurements from the high side of the GSU transformer may forget to make the proper correction when they calculate the gross values for Point “A”, as others have historically done. The scope of this

standard does not include the verification of high voltage power flow controllers that are connected to the transmission system at 100 kV or above. We propose that a Standard Authorization Request (SAR) be created to address the power capability verification gap that is not being filled with this standard. The test form has remarks space for reactive limit constraints but not for real power constraints. Attachment 1 , #2, the use of the word “all” auxiliary equipment is unnecessary and is over reaching, the Requirement is for expected normal operation. Recommend deleting “all” from this sentence. Attachment 1, # 2.1, should the SDT give an alternate threshold if “90%” could not be achieved during the testing window?
No
Yes
We agree with this proposal as being in line with our overall concern that model verification requirements should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
No
It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.
No
No
Yes
Please consider the following comments: Footnote 2 - Include the explanation that “average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value”, since historically some have asked how this factor is defined and calculated”. Requirement R3, bullet 2 – Append wording like, “such as a model is unusable by the Transmission Planner, dubious model type, abnormal model parameter values, and unusual simulation results” to the text, “technical concerns with the verification documentation”. Attachment 1, Row 6 (New or Existing Generator Unit) –Replace “Excitation control system model” with “Turbine/governor and load control or active/frequency control system model”. Comments: We have a number of questions and concerns as follows: • While the Standard uses the word “verified” and “verification” loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. • If a simulation study results in response characteristics that does not match an on-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Yes
Yes

No
Yes
No
It appears that Item 5.2.5 in the Applicability section is missing. We propose adding, "5.2.5 By the first day of the first Calendar quarter, five calendar years following Board of Trustee approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units".
Yes
Yes
No
Yes
Consider adding a note to Attachment 1, which states that the type of D curve should be specified (i.e. based on the data reported per the MOD-010 standard, the data reported per the MOD-025-2 standard, or some other basis).
Individual
Mace Hunter
Lakeland Electric
Yes
Yes
Yes
Yes
Under the section B. requirements R1, 1.1; it refers us to "attachment - 1" . Under attachment – 1, item 2 – 2.1 it states the following: • Perform verification of real and reactive power capability of all generating units at maximum over excited (lagging) and under-excited (leading) reactive capability at gross real power capability. We would like to propose adding "or to the documented limiting factor of the equipment (generator, voltage regulator, transformer, transmission etc.)". We want to avoid having to test to the min and max of the capability curve if there is some other limiting factor we can document.

Group
SPP Reliability Standards Development Team
Jonathan Hayes
Yes
No
Is there a typo in the question? Should Transmission Owner be Transmission Planner? If not then adding the Transmission Owner as an intermediate step before submitting data to the Transmission Planner isn't needed.
Yes
We feel that the entity should be the Transmission Planner, but there is a need for the Generator Owner to provide an adjustment factor. The standard should address the temperature to bring the data to and then the Generator Owner could provide the factor to adjust the data. The standard also needs to address the fact that the temperature will not be a single set number and will vary depending on the season and geographic location.
Yes
If the intent is that the team wants to follow the Compliance Registry then we would ask that there be direct language reference to the Registry. If this isn't done and the Registry changes as worded now the standard would be static to the numbers given. This team needs to get plugged into the BES DEF standard drafting team as there are discussions being held currently that could change the Registry criteria.
No
This is a non linear curve. Is the reason for using the 4 point method all that would fit into the model? We also have the concern that isn't addressed here and it is if the unit can't be tested at the time due to system conditions then you must wait until the system is able. We feel that the points should reflect what is usable.
No
Currently SPP has criteria that the testing period should be 15 minutes rather than the listed 1 hour. We have found that this time period is adequate.
No
We would request that the time be a few minutes to make sure after a settling period that it was a limit that was encountered.
Yes
Yes
We agree with the 50 MVA limit but would request that it be included in the actual standard.
Yes
No
We feel that 20% is too great a buffer for this data and would suggest that the number reflect a

buffer of 10% or less. We feel like having a buffer that is too high would cause entities to not use testing verification and would use the operational data verification. We also feel that this verification should be as accurate as possible to reflect the system in planning.
Yes
If the testing time is 1 hour as written then we have a variance of the SPP criteria of 15 minutes, but if the team decides to change that time limit then we wouldn't and our answer would change to no.
No
Yes
VSLS for R2 there is an extra applicable in the chart. Would suggest removing.
No
By setting the MVA rating at 100MVA in section 4.2.1 for single units aren't you excluding units? It is then mentioned in the bullet below that units below 20MVA are included but as an aggregate if the site is over 100MVA. We aren't clear how this is expanding the standard. The other standards in this group refer to the limits used in the Compliance Registry. Should this be consistent with those?
Yes
We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
No
No
Yes
In the VSLS for R2 there is a "no" that needs to be deleted. In VSLS for R2 and R4 there is a footnote referenced on page 2 of the draft standard so it shouldn't be included here as well.
Yes
Yes
This question refers to the applicability of the standard yet doesn't reflect the wording in this question. In the standard the applicability for synchronous condensers is 20 MVA due to it being lumped with single units. This needs to be broken out in the applicability section of the standard.
Yes
We weren't able to locate the variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites) within the standard as the question suggests. We feel like variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites should have been included but would request that the team provide a limit on the size of these types of facilities. Our team isn't sure what a cutoff number would be, but would ask that the drafting team investigate this issue to come up with an appropriate number.
Yes
No
The team would like to move out the initial 20% to 2 years and add a year to the following phases as well i.e 40% 3 years 60% 4 years etc. 5.2.5 seems to be missing from the standard which doesn't include a bullet for 100% for those who need Board approval.
Yes
While the team agrees with this evidence, some of the older units in the system may not have this information readily available.
Yes
For new units or units that haven't changed you would not have prior data to provide. The drafting team may need to think about rewording to address this issue.

No
Yes
It seems there is room for clean up in the posted standard.
Individual
John Bee
Exelon
No
The requirements of MOD-024-1 and MOD-025-1 should remain separate. The testing periodicities and the reporting requirements for both of the existing Standards are different. In addition, the SDT needs to closely coordinate with existing testing and reporting requirements 1) Regional requirements and reporting criteria (e.g., MOD-024-RFC-01.1) and 2) Transmission Planner requirements (e.g., PJM has separate reporting criteria). If the SDT continues to push for a combined Standard, then consideration must be given to splitting out the requirements (i.e., separate Attachments) for Real and Reactive Testing.
No
The Transmission Planner should be the appropriate entity to receive this data.
No
The Standard needs to address correction factors for "ambient conditions" instead of "air temperature." Specifically, large generating units are typically water cooled and therefore the correction factor should be revised as such. In addition, as stated in the response to question 2 above, the Transmission Planner should be the appropriate entity instead of the Transmission Owner.
Yes
No
Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Suggest the following revision to Attachment 1 as follows: 2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.
Yes
The time of one hour as a minimum is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the generator reactive capability curve (RCC).
Yes
Recording the test data as soon as a limit is encountered is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the reactive limits given by the plant specific generator reactive capability curve (RCC) at the attainable real power output. Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Suggest the following revision to Attachment 1

as follows: 2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.
Yes
Yes
Yes
Yes
Yes
It is strongly suggested that the SDT review each existing Generator Real and Reactive Power Capability Regional Standard (or other guidance) currently in place for best practices and potential conflicts. As stated in responses to questions 5, 7, 13, and 14 nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Exelon Nuclear is a member of and has 17 nuclear units in two Regions (ReliabilityFirst and SERC). RFC Regional Standard MOD-025-RFC-01, "Verification and Data Reporting of Generator Gross and Net Reactive Power Capability," currently has a specific exclusion that "Under-excited (leading) Reactive Power capability verification is not required of nuclear units." SERC Regional Criteria, "Verification of Generator Real and Reactive Power Capability," has the following statement regarding nuclear units, "(t)he capabilities of nuclear units will be determined taking into consideration the fuel management program of the unit and any restrictions imposed by regulatory agencies.
Yes
Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements.
Yes
Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements. Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities. Suggest that all exceptions to test performance criteria be pulled forward into body of the Standard. Additional comments for MOD-025-2 Attachment 1 • Step 2.3 – remove reference to "rated real power" - the reactive power test is conducted as a stand alone test using the attainable real power (which is generally governed by ambient conditions at the time of the test). • Step 2.4 – remove reference to "over-excited reactive capability" – the over-excited test is conducted for a minimum of 1 hour • Step 3.4 – remove reference to "correction factor: - this applies to correcting MW as part of the MOD-024 test. Reactive power is tested at the attainable MWe.
Yes
No

Yes
The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that “Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units…”.
Yes
Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities. The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. As detailed in a memorandum from Jesus (Nano) Sierrra (FERC) to John Odom (ERAG Management Committee Chair), "Follow-up on the Provision of Primary Frequency Response by Nuclear Units in the ERAG-MMWG Dynamic Models," dated April 27, 2011, most all generating units do not respond to frequency deviations; however, there are some nuclear unit designs that do have limited response to under frequency conditions. It is important to note that even if a nuclear unit' s governor design does have limited response to grid frequency deviations, the nuclear unit is administratively restricted by their respective NRC operating license requirements to 100% thermal power. It is not clear from the proposed Standard MOD-027-1 or the Implementation Plan the SDT intended implementation timeline for the first verification period. That is, when must Requirement R2 be completed for the first 25% of the Generator Owner's applicable units? The second 25%? Etc. It is confusing when considering the wording in Section A.5, "Effective Date:" combined with the wording in Attachment 1, Criteria 2 of the Standard. In addition, the Implementation Plan does not provide any further guidance. Is the intent that the staggered percentage implementation provides the start time for the generating units to complete R2 within a following ten year period? This would allow the applicable units to modify/install recording equipment and then set T=0 to then start the ten year staggered verification period. OR Is the intent to short cycle the initial verification period during implementation based on the percentage of units and then set up a ten year staggered verification period thereafter?
No
The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (top of page 7) states "(F)or the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current." This conflicts with Requirement R1.1.1 that states "… assuming normal AVR control loop and system steady state operating conditions. Currently the two statements are in conflict with one another in that one requires a "fixed" field current (i.e., AVR in "manual") and the other requires "normal operation" (i.e., AVR in "automatic"). The SDT needs to allow for automatic mode for AVR to accommodate those Generators that have redundant automatic channels as is the case for newer digital AVRs. This will allow the owner to use AVRs automatic mode when plotting SSSL.
No
Exelon does not see a reliability need to include static reactive resources in PRC-019. The standard as written is applicable to voltage regulating controls and limit functions with generator capabilities and protection system settings which is generator specific. Adding static reactive resources would require unnecessary additional guidance to be included in the standard. The maintenance and coordination of relays related to static reactive resources is currently covered in PRC-005 and modeling and studies are included in the MOD standard.
Yes
No
There is a conflict with the implementation periods stated within the body of Standard PRC-019-1 and the associated Implementation Plan. PRC-019-1 Section 5 Effective Date Step 5.1.1 states "(b)y the first day of the first calendar quarter, one year following applicable regulatory approval … " [emphasis

added]; however, the Implementation Plan states the Effective Date is "(t)he first day of the first calendar quarter two years following applicable regulatory approval … " [emphasis added]. Exelon requests that the implementation period be 2 years following regulatory approval. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). An implementation period of 2 years will allow for any modifications to existing equipment be completed during a refueling outage.
No
In addition to the methodology listed, a provision should be allowed to use an alternative acceptable methodology that meets the intent of the Standard such as a methodology that uses impedance locus for loss of field for settings for the loss of field relays. Attachment G second formula is incorrect and should be corrected as follows: R = V2 g/2*(1/Xs+1/Xd) (Divide by 2)
Yes
No
No
Group
Tennessee Valley Authority GO
David Thompson
Yes
No
The TP or the PC (PA) is the entity who will use the data. R1.3 and R2.3 specifies that the TP be given this data.
No
Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to be the same.
No
We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentialy identical units should not be required.
No
Although we agree that four points are sufficient to provide a straight line approximation over a unit's operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification, discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states: "…other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, We do not believe that verification for

leading capability should be required where operational practices preclude operation in a leading mode.
Yes
Yes
But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
No
It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate. It is noteworthy that the original NERC Board Approved version of this standard states in

requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5-year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used. We suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results. Consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) Revise attachement 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 11) It is noted that MOD-11, which is supposed to clarify modeling data requirements, has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achiving the reliablity purpose intended. 12) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators. Targeted testing can have application on a limited basis.
No
Yes
Yes
Yes
We think it is possible that the unit rating which is critical to the BES may vary from region to region.
No
Yes
It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency excursion. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. 2)
Yes
Yes
No
Yes

Yes
Yes
Yes
No
Yes
We recommend that the minimum unit rating to be applicable to this standard should be 75 MVA, and the aggregate plant size to be applicable should be 100 MVA.
Group
Luminant Power
David Youngblood
Yes
No
This is not applicable in the ERCOT region. Data should be submitted to TOP and BA. They are currently responsible to utilizing the information for grid reliability.
No
Luminant agrees that ambient test temperature and temperature correction information should be submitted to the appropriate entities. In ERCOT, this would be TOP and BA.
Yes
No
Luminant proposes the following: 1. At High Load - Maximum overexcitation and under-excitation testing shall be conducted at a minimum of 95% of real power output capability and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 2. At Low Load - Maximum overexcitation and under-excitation testing shall be conducted in the output range between minimum stable load and minimum stable load plus 30%, and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 3. Lead and lag tests can conducted independently.
Yes
Yes
See Luminant comments to Question #5 regarding operating ranges for testing.
Yes
Yes
Yes
No
No
No

Yes
Yes
No
No
No
Yes
Yes
No
Yes
Yes
In requirement R5.2 – there should be a sub-requirement R5.2.5 for 100% compliance at five calendar years?
No
This item needs to coordinate with PRC-001 (System protection Coordination) and the future PRC-023-1 (generator loadability) standard currently under development. Section G indicates a distance relay (21) but does not indicate any timers that would be coordinated with the transmission provider. Propose removing this protective relay from Attachment 2.
No
Once coordination is completed, the retention shall be until the unit is retired or a system change has occurred, plus any coordination document that was in effect during the current audit cycle.
No
No
Group
SERC Planning Standards Subcommittee
Charles W. Long
Yes
No
TThe PSS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
Yes
The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
No
The use of sisters units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability. However, the standard should apply to designated blackstart units included in a system restoration plan, regardless of size.
Yes

Yes
No
We recommend a limit of 20 MVA since these may be in remote areas where reactive capability is critical.
Yes
No
The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
Individual
Michael Goggin
American Wind Energy Association
Yes
Yes
No

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
No
Yes
Yes
No
No
No
Yes
Yes
No
Yes
Yes
Yes
Yes

No
No
Individual
Keith Morisette
Tacoma Power
Yes
Yes
No
Tacoma Power is not aware of any industry accepted standard air ambient real power correction factor for hydro units.
No
1) Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. 2) Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity.
Yes
No
Depending on the size of the unit and location in the transmission system operating the unit at full rated reactive capability with normal steady state transmission voltages may subject the plant and transmission system to a sustained overvoltage. The over-excitation limit should be verified in the same way the under-excitation limit is verified.
Yes
None
None
Yes
None
Yes
None
No
None
No
None
No
None
No
None
Yes
None
No
None

No
None
No
Yes
None
No
Even if the variable devices or their impact is well defined, such as "Devices within 2 buses and that can affect the transmission system voltage plus or minus 5% or greater", including this requirement for variable static reactive sources could involve a wide scope of devices and potentially many owners and operators for very little improvement in reliability.
Yes
None
Yes
None
Yes
None
Yes
None
No
None
None
Group
Idaho Power-Power Production
Tim Brown
Yes
Yes
Yes
No
No
Yes
Consistancy with the compliance registry and the BES definition is important.
No
No, we believe that the four points are not adequate to describe a unit's capability. FAC-008 and FAC-009 require us to have a normal and emergency rating and the WECC validation policy requires the verification of the unit's capability. Is this standard intended to replace those standards/policies? If so it was not clear in the project documentation. If not, we believe this standard to be redundant to our existing policies and procedures here in WECC.
No
No, if this is intended to verify an emergency reactive capability we believe 15 minutes is sufficient. If this is intended to verify a normal reactive capability then 1 hour is reasonable.
Yes
Yes
Yes
No

What is the technical basis for the 20%? It seems high.
No
No
No conflict, but as stated before, it seems to be redundant with FAC-008, FAC-009 and the existing WECC validation policy.
Yes
1. The language in the Applicability Section 4.2.1, implies that the standard applies to only synchronous condensers in generating facilities. Please clarify. 2. As stated before, we believe that FAC-008 and FAC-009 specify our generator have an normal and emergency rating. The standards should use similar language in requiring validation of capability. However, our regional policy required by MOD-010, specifies validation of the generator reactive capability, thus we believe this standard is redundant and not needed. That is unless MOD-010 is going to be retired. 3. Note 1 in Attachment 1 states that the data point may not match the manufacturer capability curve or the verified values for the MOD-010 standard. We question what the point of this standard is if not to validate. Note 1 mentions other items that might be discovered during the validation required by this standard, but we believe those benefits are achieved by our existing validation policy.
Yes
We believe Black Start units, regardless of size, should be considered in this standard.
No
WECC has an existing model validation policy that is well defined and established. This project documentation does not specifically state that MOD-012 and MOD-013 would be retired. If not, this policy would be redundant with the existing WECC policy.
Yes
Yes
Yes
Yes
No
We believe that the tutorial like language in Section G is not appropriate for a standard. There is an abundance of material available describing the coordination of generator protection equipment, such as textbooks, IEEE tutorials and even NERC tutorials. We believe referencing the documents could be appropriate and helpful. Even though the diagrams are listed as examples, we believe they might be interpreted a recipe to be followed.
Yes
No
No
Group
Santee Cooper
Terry L. Blackwell

Yes
Yes
No
Recommend changing Section 4.2 Facilities to match Section 4.2 Facilities as it is written in MOD-026-1 and MOD-027-1 below: 4.2. Facilities For the purpose of this standard, the following Facilities are considered, “applicable units.” Units or plants with an average capacity2factor greater than 5% over the last three calendar years that meet the following: 4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics: • Each generating unit with a gross nameplate rating greater than 100 MVA, connected at the point of interconnection3at greater than 100 kV. • For each plant with a gross aggregate nameplate rating greater than 100 MVA, connected at the same point of interconnection at greater than 100 kV: o Each unit with a gross nameplate rating greater than 20 MVA; and o The remainder of the plant as an aggregate. There should also be some allowance for Units which are nearly identical and therefore model the same.
No
The current SERC Regional Criteria requires gross and net reactive capability be determined within the power factor range at which the generating equipment is normally expected to operate. We do not believe anything is gained by testing in power factor ranges where the unit is not expected to operate.
No
First of all “expected value” is not defined. Second any expected value based solely on nameplate data is subject to great variation based on the system the generator is connected to and should not be used to draw conclusions of satisfactory or unsatisfactory test results.
Yes
Attachment 1 Item 1 requires testing of units that are 20 MVA and above to be tested a second time if they are tested as part of the aggregate.
Individual

Bob Casey
Georgia Transmission Corporation
Yes
No
This question seems to have identified the TO in error. MOD025-2 requires data to be submitted to the TP. TP is the appropriate entity to receive the data.
No
The ambient temperature and other factors that influence the ouput should be included. The GO should provide temperature dependent and other data tables/graphs to the TP. Again, the comment form and attachment seem to conflict with R1 and R2 to provide data to the TP not the TO.
Yes
No
Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability.
Yes
Yes
Yes
No
20 MVA seems more consistent with the reasoning in question 4.
Yes
No
The data should be accepted as is unless the data is meaningless.
No
No
Yes
Regarding reactive capability, the SDT has recognized that this standard will not meet the purpose “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability.” Should the standard and/or purpose be adjusted to where they match? Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability. R1.3 is unclear we propose: Submit the recorded data to its Transmission Planner within 90 calendar days of the date the data is recorded.
No
Yes
Yes
No

No
Yes
Have software manufacturers agreed to provide their models as described in R1?
Individual
Jeanie Doty
Austin Energy
Yes
No
We believe question #2 may contain a typo. The Proposed Standard Requirement 1.3 correctly requires data submittal to the Transmission PLANNER (in our case ERCOT). The data should be submitted to the Transmission Planner as currently written in the Proposed Standard, not the Transmission Owner as stated in the comment questionnaire.
No
Ambient temperature will have a less direct effect on water cooled generators with cooling water sources not directly affected by ambient temperature.
Yes
Yes
No
The ERCOT required verification time is 15 minutes. Extending the verification time to one hour is burdensome with unclear benefit.
Yes
Yes
No
This requires a guarantee to an expected performance that may be impacted by a particular operational problem during the test (high cooling water or ambient temperatures, etc). The test results should be accepted as is and logged as the new generator capability until such time as it is retested later with better results.
No
Yes
See the response to Question 6.
No

No
Yes
Yes
No
No
ERCOT has been performing computer modeling based on RARF data provided by GO's.
Yes
Since dynamic data for old units is often not available, the SDT may consider allowing the use of typical or generic modeling parameters for these units.
Yes
Yes
Yes
Yes
Yes
No
Initial compliance, within the first audit period, should be based on one evidentiary document set. Subsequent compliance, after the first audit period, may include the most current and the previous evidentiary document set.
No
No
Individual
Dale Fredrickson
Wisconsin Electric
No
The testing of reactive power capability has inherent risks due to the need for coordination with relaying and excitation limiters, and requires more technical resources than real power testing. Therefore the verification of real and reactive power would best be addressed in separate standards.
Yes
No
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
No
No
Yes
Attachment 1, 2.1 and 2.2: It would be more reasonable to allow for some small variation in real power level around the rated gross real power output and minimum real power outputs, perhaps within +/- 5 percent of these values. This would allow for variability in coal conditions, system voltages, etc. Also, the requirement in 2.1 for 90 percent of wind turbines online may be impractical in many cases. A lower value such as 75 percent may be more reasonable.
No
Yes
Yes
No
No
Yes
It is not clear how this standard would be applied to wind generators. They should perhaps be specifically exempted from these requirements.
Yes
Yes
No
The primary applicability should be to rotating synchronous machines which must have their protection settings and excitation controls properly coordinated with the machine capability. It is not clear how this can be applied to wind generators.
No
Replace the phrase "...preventing tripping..." with "...reducing the potential for tripping..."
Yes
No
The following should be added to the list in Section G: 1. under-excited limiters or minimum excitation limiters 2. over-excited limiters or maximum excitation limiters.
Yes

No
Yes
1. R1.2 needs to be clarified, and more time allowed. The phrase, "within 90 days following the identification or implementation of systems, equipment, or setting changes..." is vague, and should be replaced with "within 120 days of modifications made to systems, equipment, or setting changes...". The requirement should clarify that the clock starts 120 days after the date that the affected generator returned to service following the modifications. 2. It is not clear how wind generators can be subject to this standard. The information in Section G does not relate to wind machines.
Individual
Michael Brytowski
Great River Energy
Yes
Yes
No
GRE doesn't agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load. If they want it at different points I think they should leave it up to the GO/GOP's to decide at what other load point they want to run the test.
Yes
GRE would object to doing this at URGE because URGE is not our normal operating condition. The reactive power testing should be done at normal full load (normal operating conditions) to be representative of how much reactive power the unit can put out or absorb during normal running conditions. GRE doesn't agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load.
Yes
Yes
Yes
Yes
No
No
Yes
Please see comments submitted by the MRO NSRF for question #14

Individual
Vladimir Stanisic
BC Hydro
Yes
No
Not clear why would data be submitted to TO. Based on Functional Model, TP, TOP or PC would be more applicable.
No
Generating facilities are already designed and ratings determined based on maximum expected ambient temperatures. Besides, equipment cooling may not be directly dependent on ambient temperature. Providing the details to other entities would be of no practical value. GOs have to meet declared capabilities as registered or derate their facilities if needed.
No
In principle, using compliance registry as a sole criteria for applicability of Reliability Standards removes technical evaluation and justification from the process. The value that technical experts participating in SDTs may add becomes limited, which ultimately does not benefit the industry.
No
Technically, only verification at the maximu rated active power output has practical value since it is the most limiting operating condtion in terms of reactive power capability. Verifying reactive power capability at lower active power outputs is redundant because: 1. The capability will obviously be somewhat higher than at maximum active power output 2. Registration data normally include only Qmax and Qmin, which are determined at unit's rated active power output. 3. Reactive capability does not depend on unit's active power output as much as on other factors, such as system or station service voltages D curve is developed based on calculated data. The purpose of this should not be verification of the curve
Yes
It may be better to specify a particular rate of change of measured temperature determining that heating has stabilized instead of selecting an arbitrary time period.
Yes
Only verification of (1) has practical significance; (2) and (3) are redundant. Please see Comment 5.
Yes
Not clear why would verification be required for generating units over 20 MVA while for SCs the threshold is over 50 MVA, especially having in mind that SCs are specifically used to provide reactive support
Yes

No
Such a wide margin seems to defeat the purpose of verifications. If such margin is technically acceptable to planners, the question is why even requiring verifications, especially for smaller units. It is hard to immagine that actual capability (active or reactive) of generating units/facilities would ever be lower than 80% of declared.
No
No
No
No
Yes
This standard would not apply to SCs in any case
No
No
Yes
The standard apparently favours ambient monitoring as a verification method. While this method has certain advantages over methods traditionally used to verify response of turbine-governors (off-line and on-line step tests), it should be well understood that its implemention is associated with additional costs and difficulties. The question is how would GOs make use of ambient monitoring data to verify the models? GOs are responsible only for equipment models and would not normally have overall system models which are necessary to evaluate the results of ambient monitoring. That puts the focus back on traditional approaches.
Yes
No
Yes
Yes
Yes
Yes
No
Yes
The note in section G may have to be revisited. The main issue is that active excitation limiters can prevent a unit from unneccessary tripping during system transients. The standard should encourage activation and proper setting of avaiable excitation limiters
Individual
Michael Lombardi
Northeast Utilities

Yes
No
The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Yes
Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
No
Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Yes
Yes
No
Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.
Yes
Yes
Yes
Yes
No
No
No
No

No
A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
No
Can’t generators be operated as synchronous condensers if needed?
No
No
Yes
In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
No
This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
No
Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Yes
Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage]. Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
No
Modify the wording to reflect all ‘real and reactive power sources,’ not limiting it exclusively to traditional rotating machinery.
Yes
Yes
No
The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
No
Yes
Related to the “Examples of Coordination”, the P-Q diagram, the R-X diagram, and the Inverse Time

Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Group
Lakeland Electric
David Miller
Yes
Yes
A Transmission Owner may need to size conductors according to Generator output.
No
It should be acceptable that the Real Power data collected during credible, high-ambient temperature conditions be used to establish Real Power output limits throughout the year, including during lower temperature ambient conditions. By limiting Real Power output to that determined for high-ambient conditions, system reliability will not be compromised during lower ambient temperature conditions/scenarios.
Yes
In the VSL table for Requirement R2, the word “applicable” appears twice in a row in the “Lower VSL” and “Moderate VSL” columns. Propose striking one instance of the word.
Yes
No
The word “prior” lacks specificity. Proposed: “…shall retain the latest evidence of compliance with Requirement R1, Measure M1 dating back to most recent audit period.”

Group
PPL Generation
Annette Bannon
No
MOD-024 has already been incorporated into a regional standard by RFC (MOD-024-RFC); and, as is implicit in the term "standard," these documents should change only infrequently.
No
PPL Generation, LLC's Registered Entities are already performing VAR testing and reporting the results to our RTO (PJM), in accordance with Manual PJM-14D, and PJM then makes this information available to other entities. It would be very confusing to have to conduct two different VAR tests (PJM and NERC), possibly resulting in two different values (depending on the final wording of MOD-025), reported to two different entities.
No
The correction of real power capability to other-than-tested ambient conditions, as is currently performed by PPL Generation Registered Entities for MOD-024-RFC, is a complex matter involving the wet-bulb temperature, condenser cleanliness and other factors beyond simply the dry-bulb temperature, especially when using a total-unit thermodynamic computer model for this purpose. One must also consider low-ambient limitations; wintertime predicted capabilities must be truncated if they would otherwise exceed the generator or GSU rating. Corrections to other-than-tested ambients should be performed by the GO, using an on-request basis.
No
The applicability of this standard should include, "and having a capacity factor for the past three years averaging over 10%." As presently written this standard would require VAR testing of a small, emergency genset if located in a baseload facility interconnected > 100 kV.
Yes
The proposed verification at multiple points over a unit's operating range appears to derive from a belief that the verification test results will follow the generator OEM's D-curve; and, owing to the abnormal voltages created by VAR testing and aux bus drop-out limitations; this will not be the case.
No
The one-hour period appears to derive from D-curve (thermal limiting) expectations; and, as explained above, this will not be the case
Yes
Yes
Yes
Yes
Yes
Note however that the expectation, as discussed above, is (for certain PPL Generation Registered Entities' units) derived form the aux bus limits, not the D-curve.
No
Yes
Ref. the inputs made above, there should be just one VAR test, with a single set of results going to all parties.
Yes
PPL offers the following comments on Attachment 1: Att. 1, para. 2: Change the final sentence to

end, "within 20% of the expected real and reactive power values." Reason: Clarification Att.1, footnote to para. 2.1: Change "normal expected maximum" to "normal," and "at the time of the verification" to "for the ambient conditions during the verification." Reason: Clarification. The normal output of a unit is often not its (emergency) maximum generation, and the word "ambient" works better than "time." Att. 1, para. 2.1, 1st sentence: Change "at rated gross Real Power capability" to "within 20% of the Real Power capability." Reason: Clarification, see the comment above to para. 2. Also, the terms capability and rating have different meanings. Att. 1, para. 2.1, last sentence: Change "possible" to "practical" Att. 1, para. 2.2: Change exception in 1st sentence to "other than wind, photovoltaic and peaking (capacity factor < 10%)." Reason: Given that peaking units typically operate only during periods of maximum demand, it can be difficult to establish a realistic min power expectation, this exercise would add little or no value, and such testing would be unnecessarily economically burdensome. Att.1, para. 2.3: Add at end, "for baseload units. Values for peaking units (<10% capacity factor) may be recorded as soon as they are reached. Reason: The dispatch volatility of peaking units can make a one-hour hold-period unnecessarily economically burdensome. Att. 1, para. 2.5: Add at end, "if attainable. Otherwise a 10% variation is acceptable" Reason: Hydrogen pressure can vary, and minor disturbances should not disquality an otherwise-acceptable test. Att. 1, para. 3.2: Clarification is needed. Is the standard saying that a special-for-test voltage schedule should be established with the RTO? Att. 1, para. 3.3: Add at the end, "one or the other of these values may be calculated, if metering is not present at both locations." Reason: Same concept as para. 4.1. Att. 1, Note 1, 1st sentence: Add at the end, "or unit auxiliary system voltage limits or facility operational practices." Make the same change also for "transmission system conditions" in the third sentence. Reason: VAR testing involves creating abnormal voltages at the generator terminals and in the feeds to auxiliary equipment. Drop-out of aux motors can constitute the practical test limit. It is appropriate to apply safety margins in this respect (ref. facility operational practices), lest units be at risk of tripping in the course of conducting a reliability test. Att. 1, Note 2: Clarification is needed regarding the less-restrictive conditions being referred-to. Att. 1, para 3.4: Replace "and a correction factor...if needed" with "and, if requested, correction to other ambient conditions." Reason: Correction often involves more than a simple multiplication factor, especially when using a thermodynamic computer model for this purpose. This exercise includes truncating corrections to lower ambients for GSU and generator limits, if necessary. General: The generator OEM D-curve constitutes a rating, not a capability, and is applicable only at rated voltage. VAR testing involves identifying a capability at abnormal voltages, and is thus likely to rarely if ever match the D-curve. General: Where the RTO has an effective VAR testing program in place (as is the case for PJM) the results should be acceptable as-is for NERC compliance purposes, lest there be created two different tests, resulting in reporting of two different reactive capabilities to two different entities.
No
Yes
Yes
No
No
Yes
PPL Generation suggests the following changes: 1. Increase the capacity factor threshold identified in the Applicability Section from the current 5% to 10%. Otherwise, ambient monitoring may be required for an excessively long period. 2. Allow the use of OEM-provided governor models and, if adequate, existing models to satisfy the requirement in R2. OEM models can have equivalent-or-better validity than on-line testing. 3. Define what response is expected to be documented for Requirement 2.1.1 (as pertaining to a time-frame of 30 seconds or less, and to sudden frequency dips, not step-increases). Units have an immediate response (e.g. opening the control valves) and a long-term response (e.g. ramping-up the coal feed). Governors (the subject of this standard) deal only with the former category. Ambient monitoring should eventually provide a frequency-dip event to analyze, but the same is not true for opposite-direction events. 4. Should the recorded response in

Requirement 2.1.1 be the predicted response? It appears that the on-line response and the recorded response are the same thing. 5. In Requirement 2.1.1, clarify under what circumstances a lack of response constitutes suitable verification, e.g. experiencing a frequency drop for units running valves-wide-open or CTGs at baseload firing temperature.
Yes
No
See item 1 in Question 9 Response.
No
No
As stated in comment 2 for item 9 below, NERC is not being consistent in using the term "capability." It refers in other standards to that which can be achieved, not to the condition at which tripping is needed.
Yes
No
Yes
No
See comment 2 for item 9 below.
Yes
PPL Generation suggests the following changes: 1. Consider making this standard applicable to generation facilities having a capacity factor for the past three years averaging over 10%. The basis for this request: As presently written this Applicability would require compliance for a small, emergency genset if located in a baseload facility interconnected > 100 kV. 2. In Requirements R.1, R1.1.1, R1.2 and elsewhere where the term "capability" is used, consider using the term "trip limit". As currently written, it appears that Requirement 1.1.1 is semantically misdirected in requiring protectives to be set below equipment capabilities. A capability is what the unit can actually do (ref. MOD-024 and 025). It is not the limit beyond which damage, instability or other problems may occur. A unit with a 875 MVA GSU and 900 MVA generator, for example, may have a real power capability of only 750 MW based on boiler and turbine limitations. It is not possible to have trips set below a unit's capability, unless PRC and MOD apply different meanings for this term, which would not be suitable. Confusion may be caused by generator D-curves also being called “capability curves,” but here also one would not want to require that generator never be operated at the D-curve value.
Individual
Amir Hammad
Constellation Power Generation
Yes
Yes
No
Constellation Power Generation (CPG) agrees with this approach.
No
Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
Yes

CPG agrees that the points chosen would provide a sufficient approximation of a unit's capabilities. However, these capabilities will never match a generator's capability curve for a multitude of reasons, and as such, some verbiage should be included in the attachment under item 2 instead of as a note at the end of the document. Further, the limitations on the unit that may not allow the unit to perform to its capability curve are most likely designed into the control system as limiters or protection system components so as to not allow damage to the unit. These designed controls should not be "investigated for resolution" as stated in Note 1.
Yes
Yes
Yes
Yes
Yes
Yes
No
No
Yes
CPG is concerned with the general wording of Attachment 1 as the verbiage is not auditable. For example, Item 2.1 states "Maintain as steady as possible Real and Reactive Power output during verification." The term "steady as possible" is extremely subjective and open to a multitude of interpretations. From a technical perspective, item 3.3 is not auditable because it is assuming that the voltages and the high and low side of the GSU are metered. This is usually not the case. A statement allowing for an entity to report on the requested metered points based on their configuration and allowing for some points to not be answered would be preferable. Likewise, Attachment 2 would require a similar statement.
No
No. CPG believes that the use of capacity factor, a variable data point, in the applicability of a standard is too problematic. Capacity factor is a market a function that is dependent on many variables outside of reliability and therefore does not belong in a reliability standard. CPG is also unsure as to how the SDT arrived at the MVA thresholds in each of the Interconnections, and is requesting that a technical justification of those thresholds be submitted along with the response of comments.
Yes
Yes
No
No
Yes
CPG is unsure as to what Requirement 2.1.1 is actually requiring. Please explain the difference between an on-line response to a frequency excursion vs. a recorded response. This sub requirement seems to be implying that each GO has the necessary equipment to capture an on line or recorded response. Is it the intent of the drafting team to force GOs to install equipment in order to comply

with R2.1.1 along with the conditions found in Attachment 1? CPG would also like clarification on Requirement 2.1.5. Outer loop controls don't affect the governor control (frequency loop). Lastly, CPG would like the SDT to describe how a GO will know that a frequency excursion event occurred on the BES if their facility was unaffected and the facility did not have equipment sensitive enough to measure within .15 Hz.
No
Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
No
Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
No
No
Although CPG believes that the purpose of this standard is valid and accurate, it closely resembles the purpose of PRC-001 and therefore the requirements drafted in PRC-19 should be rolled into a revision of PRC-1.
Yes
No
CPG believes that engineering documents detailing the coordination of the these components should be sufficient in lieu of coordination plots requiring software that is not commonly used by generators.
Yes
No
No
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Yes
No
The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Yes
Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without

inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be “what you see is what you get”; adjustments should not be accepted.
No
Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by BES SDT.
Yes
Yes
No
We recommend allowing the Transmission Operator (TOP) flexibility in determine the specific detailed nature of the reactive power tests performed in support its modeling. Regarding Part 2.1, in the NYISO, the maximum reactive power is tested at a real power level above 90% of maximum real power capability. The test was designed in this manner for a two reasons: (1) not to be a simultaneous test with 100% real power test and (2) to provide a reliable maximum reactive power test when the unit is stressed, but is still capable of providing reserve power. We recommend providing the TOP flexibility in this requirement by allowing reactive power to be tested above 90% of maximum real power capability. The NYISO Ancillary Services Manual also contemplates that GO’s will test lagging and leading reactive power during time periods more appropriate to their use. On p. 28 and p. 34 the manual states: • Lagging MVAr capability testing will normally be performed during on-peak hours. The VSS Supplier must operate at maximum Lagging MVAr for at least one hour for the test to be acceptable. • The Leading MVAr testing will normally be performed during off-peak hours. The Leading MVAr test shall be scheduled with the corresponding TO, who will inform the NYISO. Ref: http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf Presumably, under the NYISO tariff the leading and lagging Reactive Power tests would not be performed at the same time or necessarily at the same “rated gross Real Power capability.” ISO-NE also notes that maximum leading and lagging reactive power may not be at the same real power output level. • Points #4 and #9 in Figure #1, the two [lagging and leading] break points, do not necessarily correspond to the same MW output of the Generator. Ref: http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14b_rto_final.pdf Proposed language change to MOD-025 Attachment 1: 2.1. Perform verification of Real and Reactive Power capability of all generating units at maximum over-excited (lagging) and under-excited (leading) reactive capability at rated gross Real Power capability1, or at the Real Power level stipulated by the Transmission Operator. ...
Yes
Yes
Yes
Yes
No
No
No

No
No
A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
No
Can't generators be operated as synchronous condensers if needed?
No
No
Yes
In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
No
This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
No
Generally only units larger than 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by the BES SDT.
Yes
Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage]. Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
No
Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.
Yes
Yes
No
The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
No

Yes
Related to the “Examples of Coordination”, the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Individual
Thad Ness
American Electric Power
Yes
In general, AEP is not opposed to combining MOD-024-1 and MOD-025-1 into a single MOD-025-2 standard.
Yes
Draft Standard MOD-025-2 provisions 1.3 and 2.3 both state that the data be provided to the Transmission Planner, rather than the Transmission Owner as stated within this question #2. We agree that the Transmission Planner is the correct recipient for this data.
Yes
Again, we believe the question should be associated with the providing of ambient temperature and correction factor information to the Transmission Planner and the Resource Planner rather than the Transmission Owner. We believe the Resource Planner should provide the ambient temperature value, while the Generator Owner should provide the correction.
Yes
Yes
The results of the test may not accurately reflect the VAR capability due to system conditions or alarm stopping the test and not reflect the actual generator limit in a real time scenario. This is discussed in Notes 1 and 2 of Attachment 1.
Yes
This requirement is stated in Attachment 1, section 2.3.
Yes
This is stated in Attachment 1, section 2.4. A clarification could be in order to relate the recording of the time when the limit is reached to the requirement that the test be conducted over a one hour interval. For example, if a limit is reached in 15 minutes, is the verification test completed or is the expectation that the unit is held at that level for the balance of the one hour test window. Also, it is curious why this question excludes the condition of over-excited reactive capability at the rated gross real power per Attachment 1, section 2.1.
Yes
Yes
The current draft of the standard in section 4.2.1 proposes that the size of synchronous condensers to be verified be limited to those greater than 20 MVA, not 50MVA as stated in this question. Regardless, either limit would be acceptable.
Yes
No
System conditions greatly affect the expected reactive power values as stated in Attachment 1, Notes 1 and 2. While 20% appears reasonable for the real power verification, there needs to be flexibility as to this value for reactive power, given that system conditions are not constant.

No
With respect to reactive power, AEP is not aware of any regional variances that would be required for this standard.
No
AEP is not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
No
No
Yes
Yes
Synchronous condensers respond to changes in voltage and not frequency, and as a result, have no place within the scope of this standard.
No
AEP is not aware of the need for any regional variances that might be required as a result of MOD-027-1.
No
AEP is not aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
Yes
Standard models may not be available for wind units and wind facilities (which appear to be within scope of 4.2), particularly aggregate reactive and frequency response controls. As a result, it might be difficult to obtain and provide such information.
Yes
Though we agree that the standard as written is “technology neutral”, its apparent neutrality might well be impacted by the definition of BES which is currently being revised. This topic might need to be revisited once the revised definition of BES has been approved.
No
It needs to be explicitly stated whether or not a Transmission Owner is held under R1 if they do not own synchronous condensers. This might be achieved by adding additional language to 4.1.2 stating that the standard applies to those who own facilities as specified in 4.2. Usage of the words “coordinate” and “coordination” seems ambiguous, and might be open to interpretation. In other standards these words are often used to describe communication between NERC functions rather than ensuring that necessary and sufficient settings exist among equipment types to permit them to operate in a pre-determined sequence. The threshold of 50MVA is not mentioned in the draft standard. Rather, 4.2.1 specifies a threshold of 20MVA. It appears the term “synchronous condenser” has been omitted from R1. Suggest using "Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate its generating unit, generating Facility, or synchronous condenser voltage regulating system controls, including limiters and protection functions with the generating unit and Facility or synchronous condenser capabilities and protective system settings; to include as applicable".
No
AEP sees no benefit to the reliability of the BES in adding to this standard the controls associated with static reactive resources.
No
We are concerned by the inclusion of “protection system settings” in how it might differ from, or be confused with, the NERC defined term Protection System. The term “generator capabilities” should be removed from the purpose statement (as well as the requirements), as it is general enough of a term to make proving compliance difficult.
No

In light of the many other changes to standards currently proposed, and their implementations, AEP would suggest an additional year to the proposed implementation schedule to ensure a successful adaptation to PRC-019-1. The effective date for the 20% compliance milestone is inconsistent between the draft standard and the implementation plan, with one document allowing one year for compliance and the other allowing two years.
No
There appear to be inconsistencies between the standard and appendix G. the standard uses the term “protective system settings” and “protection system settings” while the appendix uses the term “protection function”.
Yes
No
AEP is not currently aware of any need for regional variances to this standard.
Yes
Measure 1 states the need for “one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2.”, yet this would not be required by the standard until five years following the initial coordination.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP agrees that generator reactive testing necessarily requires validation at the real power extremes. This means there is no benefit to require separate testing.
No
Cogeneration LP believes that the proper recipient is the Transmission Planner. The Transmission Planner in turn must supply the information to the Planning Authority, Reliability Coordinator, and/or Transmission Operator as needed. There is no apparent reason why the Transmission Owner should be in the loop. Attachment 1, Item 3.4 seems to be the only place in MOD-025-2 that the Transmission Owner is shown as the recipient of generator verification data. It should be changed to Transmission Planner – consistent with the rest of the standard.
Yes
As with question #2, we believe the appropriate recipient of generator verification data is the Transmission Planner, not the Transmission Owner. Secondly, the Generator Owner providing the validation data must also be responsible for any corrections based on ambient temperature – as there may complexities beyond temperature correction factors. In these cases, if the TP performs the calculation, they may otherwise assume more capacity is available in their contingency assessments. The GO should have the option to provide the actual validation results to the TP with a temperature correction factor, but ultimately that decision rests with them. Third, the Transmission Planner must provide the required operating temperature range necessary for their system models. This will assure consistency among generators operating within their planning jurisdiction. If there are any discrepancies between the GO’s and TP’s expected range of operation, they can work that out through an iterative resolution process – similar to the structure suggested in MOD-026-1 and MOD-027-1.
Yes
These applicability criteria are consistent within the Regions that Ingleside Cogeneration has familiarity with (TRE, WECC, and SERC).
Yes
These operating points are more than sufficient to validate reactive capability in accordance with FERC’s directive. However, Ingleside Cogeneration LP believes that it is sufficient and far less risky to perform the validation at the TOP’s reactive capability schedule limits. In addition, there needs to be an allowance for known equipment limitations which prevent testing at the four test points. Similarly, unforeseen limitations which are determined during testing may prevent the validation at every extreme.
No

Ingleside agrees in principle that one hour is sufficient at this test point, but believes it should take place at the limit identified in the Transmission Operator’s reactive capability schedule.
No
Ingleside agrees in principle that a demonstration that the generator can reach these test points is sufficient, and reduces the risk to the equipment. However, the limits identified in the Transmission Operator’s reactive capability schedule should be verified, not the generator’s operational limits.
No
There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.
No
There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.
Yes
There is no reason to preclude the use of actual operations data in validation exercises.
No
The real and reactive capacities should be validated to be within 20% of expectation at the limits identified in the Transmission Operator’s reactive capability schedule, not the generator’s operational limits.
Yes
TRE, WECC, and SERC have similar but slightly different requirements. It is Ingleside’s expectation that these regions would align their processes to MOD-025-2 when it takes effect.
No
No
No
Yes
MOD-027-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES frequency response – and have already the recording equipment needed to validate performance.
Yes
There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Yes
In the TRE region, there is already a generator governor/frequency response standard under development. It is not obvious to us that the TRE standard aligns with MOD-027-1.
No
Yes
Like many Generator Owners, Ingleside Cogeneration LP has limited experience with transmission system modeling and scenario planning. Although in general we have a good working relationship with our Transmission Planner, MOD-027-1 may border on exchanging information which either entity may consider to be proprietary. In addition, the extra costs required to deploy recording equipment and to engage external experts to assist with frequency response planning are not budgeted. With

this in mind, a priority deployment may be more appropriate – where the most critical facilities in each Region are evaluated first.
Yes
Ingleside Cogeneration LP's gas and steam turbine units use voltage limiting and protection system technologies which are clearly referenced under PRC-019-1.
No
PRC-019-1 is appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System – this determination should rest with them.
No
Ingleside Cogeneration LP is hesitant to require validation of components which have not been clearly identified as a reliability imperative under either the revised definition of the BES or CIP-002-4's bright-line criteria.
Yes
Yes
The five year phased-in validation of settings is sufficient for Ingleside Cogeneration LP.
No
Ingleside Cogeneration LP agrees with the concept of establishing a mode of operation that allows voltage regulators and limiters the first opportunity to deal with a voltage transient well before the corresponding Protection Systems are activated. However, we are concerned that protective relay settings must be always set in accordance with the Steady State Stability Limit (SSSL) as defined by NERC. There may be factors that are more limiting which require more sensitive settings – which should be acceptable if demonstrated on a P-Q, R-X or similar graph.
Yes
No
No
Group
Dominion
Louis Slade
Yes
No
R1.3 and R2.3 require submittal to Transmission Planner, not Transmission Owner. We believe it is also appropriate to submit these results to the Resource Planner as we are unaware of an existing reliability standard that requires this information be provided to that entity (even though aware that version 5 of the Functional Model (on page 28) states the Resource Planner "Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans." Further, we believe it is also appropriate to submit these results to the Balancing Authority and Transmission Operator despite the fact that they may request verification pursuant to TOP-002a @R13. We believe that, given the owner is being required to verify real and reactive capability, and report the results to one entity, requiring reporting to additional entities who could find the information useful in its reliability assessment (whether in the planning or operating time horizon) adds significant value at little additional effort.
Yes
We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that compliance with this standard be based solely upon the requirements contained

within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Yes
No
We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that compliance with this standard be based solely upon the requirements contained within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Yes
No
For items 2 and 3 see comments in question 5. We agree with item 1.
Yes
No
First, we would like to state that we did not see the 50 MVA threshold in the posted version of this standard. And, if we had, we would not have agreed. If 20 MVA is the appropriate threshold for a generator, it is appropriate for a synchronous condenser.
Yes
No
If the question was meant to ask whether we agree with the sentence that reads" Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" (Attachment 1, @2) tehn we respond affirmatively. However, we do not agree that a verification MUST be within 20%. It is possible that a physical change to either the asset being verified or the system it is interconnected with may result in its inability to perform to within 20%. If this is true, then we could agree that any such variance must be accompanied by an explanation as to why the verification did not fall with the 20% 'boundary' There should be no requirement for percent of expected value.
No
No
Yes
Test form needs to be improved. Provide the form in format that can be electronically completed by the user.
No
Yes
Yes
No
No
Yes
While we understand that a significant portion of the industry supports the 5% capacity factor threshold, we believe that this term is subject to different uses by various entities and parties,

particularly biased as to whether one is discussing capacity or energy. We suggest that, for the purpose of this standard, capacity factor be described as defined by NERC GADS. Please elaborate on Requirement 2.1.5. Also, we believe that “Load Control” and “AGC” are the same. R3, the third bullet, we suggest that “did not match the recorded response for three or more transmission system events be changed to “did not approximate the recorded response for three or more transmission system events “ We believe there needs to be an exception allowed if a frequency event does not occur in 10 years. What is “staged test” mentioned on Attachment 1? Also Attachment 1 is very confusing and should be rewritten.
Yes
Yes
No
Yes
No
The effective date implementation schedules contained in the standard and the associated Implementation Plan do not agree. Specifically, the standard indicates one year following regulatory and/or Board of Trustee approval where as the Implementation Plan indicates two year. Additionally, the standard at Step 5.2 does not include a sub-step for 100% of applicable units.
Yes
Yes
No
Yes
1) the phrase “Generating equipment”, in the 3rd bullet of R1, be changed to “Generator” to be consistent with the usage under bullets 1 & 2. 2) The title and purpose of the document do not address synchronous condensers as addressed in Requirement R1; 3) if the standard includes synchronous condensers, why are static VAR compensators not included? The following bullets under R1 are too generic. Should specifically outline required parameters. In-service 1excitation system and voltage regulating system control, limiters and protection functions • In-service generator or synchronous condenser protection system settings • Generating equipment or synchronous condenser capabilities • Steady state stability limit We recommend replacing the bullets with the following: • Generator or syn. Condenser capability curves. • Steady state stability limit. • Loss of field zone 1. • Loss of field zone 2. • Loss of field trip. • Under excitation limiter. • Over excitation limiter. • Power factor line. • Backup over current settings. • Instantaneous field current trip. • Instantaneous field current limit. • Volts per hertz.
Group
Salt River Project
Cynthia Oder
Yes
Yes
No
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
Yes
Yes
Yes
No
No
No
Yes
Yes
No
Yes
Yes
Yes
Yes
No
No

Individual
Hamish Wong
Wisconsin Public Service Corp
Yes
Yes
Yes
Yes
Yes
No Comment.
Yes
Yes
No
Synchronous condensers are specifically for local area voltage regulation purposes. Units between the sizes of 20MVA to 50MVA could be significant to an area's dynamic performance under contingencies.
Yes
No comment.
No
No
No
No
Yes
We agree with this proposal as being in line with our overall concern that model verification requirements should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
Yes
It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.
No
No
Yes
We have a number of questions and concerns as follows: • While the Standard uses the word “verified” and “verification” loosely, it is not precisely clear what a GO would have to do to satisfy the

verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. • If a simulation study results in response characteristics that does not match an on-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? • We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Group
FirstEnergy
Sam Ciccone
Yes
We agree that a “one-stop-shop” approach is appropriate for Real and Reactive Generator Verification requirements.
No
The standard in Subpart 1.3 says that the Transmission Planner is the entity that shall receive this information. We agree that it should be the TP. Also, we question whether or not the Planning Coordinator should also receive this information. Furthermore, with respect to how this information will be used by the planning entities, the team needs to assure that there is no duplication of efforts with MOD-010-0 and MOD-011-0. We suggest that MOD-010-0 and MOD-011-0 get revised to remove redundancies, or make it clear the the entity may supply existing MOD-010/-011 compliance evidence to show compliance with MOD-025-2.
No
We believe that it is the responsibility of the Generator Owner to have an appropriate Ambient Adjustment Methodology and make the necessary corrections to the data per its methodology before submitting it to the Transmission Owner. We suggest similar requirement regarding ambient ajustments as found in regional standards MOD-024-RFC-01 and MOD-025-RFC-01.
Yes
We agree that this standard should be consistent with the NERC Compliance Registry.
No
As a TO, we rank the importance to the modeling effort as follows: (1) Pmax, Qmax; (2) Pmin, Qmin; (3)) Pmax, Qmin. We believe that the Pmin, Qmax is of little value to a Planning Engineer.
Yes
Although we are OK with the 1 hour interval, we are not convinced this will meet the reliability goals

of the standard. Just being able to hit a specific reactive output is one thing, but that does not assure Reliability. Most large generators and large main transformers have only reached one, possibly two, thermal time constants within an hour timeframe There are many thermal problems that can be identified if the electrical equipment is permitted to be operated at high load levels over an extended period of time. It may be necessary to show that reactive output can be maintained over a longer period of time.
Yes
Yes
Yes, we believe they should be verified because they are the same type of dynamic, voltage independent, source of reactive power as is a real power generator. We also believe that they certainly are generators, generators of reactive power. In fact, they are identical in function, design and equipment as a real power generator, minus the prime mover. A synchronous condenser, like its sister the real power generator, can be continuously adjusted for the desired output and contains equipment that must be properly adjusted to provide the desired range of reactive output.
Yes
The applicability section does not mention the 50 MVA threshold.
Yes
No
If the generating unit is capable of reaching 20% of the "expected value", than why should verification be concluded at that point? (We could potentially be missing out on fully realizing the potential of a reactive resource by pre-maturely ending the verification. A very important dimension of this verification (that was touched on in the Standard) is the recognition of equipment conditions or voltage regulator settings that could be improved when a staged test is performed. It is difficult if not impossible to capture equipment shortcomings or limitations which can be very useful to improving operations when verifying through the use of Operational data. Also, we need clarification regarding what would be considered “within 20% of expected value” if your leading reactive limit was 0 MVAR (unity)?
No
Yes
Regional Entities such as RFC currently have Real and Reactive standards in place for its members and will need to evaluate the need to keep their standard or revise it to remove any inconsistencies that may exist. One inconsistency is the periodicity of verification for real power.
Yes
Regarding Notes 1 & 2 in the standard: Generally we have found that reactive power limitations that originate inside the generating station (hydrogen pressure, thermally sensitive generator, voltage regulator settings, and excitation problems) usually cannot be overcome through engineering analysis on the part of the transmission planning engineer. These types of conditions can only be addressed by the GO. On the other hand, Generator Terminal Voltage limits, or Transmission System voltage Limits can be eliminated using engineering analysis to simulate a more stressed system. Attachment 1, R2 – Assuming there are no transmission system related limitations, how close does the test value for VARs have to come from the expected value to be considered “verified”? Attachment 1, R2.2 – Nuclear units should be exempt from having to test leading VAR capability as this would challenge the plant’s licensing limits for safety bus minimum voltage. MOD-025-RFC-01 currently allows this exemption for nuclear plants. Attachment 1, NOTE 1 – For clarity, nuclear plant safety bus voltage limits should mentioned as a reason why D-Curve values may not be met during a test.
No
Yes
Yes

No
No
Yes
As a result of the 2010 NERC Generator Governor Survey, it became clear that many nuclear units (and I believe all of the BWR units) do not respond to changes grid frequency because their governors are controlling steam pressure. The standard should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that "Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units…". For those nuclear units that are able to respond to overfrequency events there is a possibility that a response to a system transient may not be seen during a ten year period. Since responding to an overfrequency event will result in a drop in unit load and a corresponding change in reactivity, the governor control dead band, which is set to minimize the possibility of a spurious reactivity change, could be large enough to ignore an event that meets the frequency excursion threshold (for example a 0.1 Hz dead band would ride through on a 0.07 Hz excursion). Likewise a nuclear unit would not perform a frequency reference change input test with the unit on-line because of the resulting change in reactivity. Would injecting a frequency signal to the EHC during off-line calibration and noting the response be acceptable?
Yes
Yes
Although we agree with the applicability, the standard that was posted does not mention the 50 MVA threshold.
No
Yes
Yes
At the moment we do not have comments on the proposed measures. We will review the proposed measures on the next draft and provide out input.
No
Section 1.2 of the Compliance section is missing a time frame for data retention. Timeframes consistent with CEA routine audit cycles should be added to this section.
No
We are not aware of the need for a variance at this time.
Yes
M1 requires that the GO will have evidence that "…voltage regulating system controls and protection functions are coordinated with the generating unit and generating Facility capabilities and protective system settings applied to in-service equipment as specified in Requirement R1, Section 1.1, and one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2." For the first verification cycle this would require that units would have to prove compliance as much as 4 years before the standard became enforceable. This is akin to setting up a traffic camera in a 35 mph zone in March, changing the speed limit in that zone to 25 mph in July, and going back and writing tickets for every car that exceeded 25 mph from March through June. This needs to be clarified. Requirement R2 (shown as 1.2 in the standard) should have a violation risk factor of MEDIUM instead of HIGH. Furthermore, it seems that the phrase "within 90 days of making a change to the generating equipment, voltage control limiter

settings, or protective function settings that would affect the coordination” is not necessary because a change to equipment setting would already require coordination per Requirement R1. We suggest removing this part of 1.2 (or R2).
Individual
Gary Chmiel
GE Energy
Yes
No
No
Yes
The second bullet, in part B “Requirements,” section R1, page 4: The word “library” should be removed from the phrase “system model library block diagrams,” since not all wind manufacturers have standard library models.
The fourth bullet in Part G “Reference,” paragraph beginning with “Equipment limits,”, page 6: The word “stator” should be removed, in order to make the over voltage protection limits applicable to non-synchronous machines.
Individual
Kathleen Goodman
ISO New England
Yes
No

The data from MOD-25-2 should be submitted to the Transmission Operator. The Transmission Owner does not appear to be the correct functional entity. The Transmission Owner may not have the area view required for this testing. Real and Reactive Power Testing must be coordinated with the Transmission Operator to ensure that the system remains within all operating limits.
No
We maintain that temperature correction should be performed as required by the Transmission Operator. The standard must ensure that accurate data for gas turbine and combined cycle generators is obtained which can be adjusted to reflect the ambient temperature presumed in Planning Assessments.
Yes
Yes, however the standard should not rewrite the Compliance Registry as attempted in section 4.2. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry's wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity's restoration plan. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
No
Performing testing for lagging capability at minimum real power output especially would require an inordinate amount of planning to ensure that transmission voltage levels in the local area are not exceeded. Testing requirements should be changed to two points, one for an hour to verify over-excited reactive capability at rated Real Power and one at minimum Real Power output to verify under-excited capability. Also the test of leading capability at minimum real power loading should be held for five minutes. These tests are adequate to verify critical characteristics of the generator for use in studies. The four point tests may be difficult to obtain given system configuration and operation.
Yes
Yes, the standard should also require a recording of generator vibration during the test and require that the Generator Owner report an increase in vibration over the test period indicating the presence of rotor shorted turns that would limit long term generator MVAR loading. One hour may be enough time to determine if rotor shorted turns are present as indicated by vibration but the vibration must be recorded. The reactive power output data recording should be at 5 minute intervals and use the average for the hour. Also testing leading capability at minimum real power loading should be held for five minutes.
No
These types of tests should require remaining at the point for a length of time. Under-excited power verification at minimum power output for five minutes should be adequate. Testing requirements for over-excited reactive capability at minimum real power output and under-excited capability at maximum power should be removed. These tests lead to transmission system voltage concerns.
Yes
Yes, but as written the standard is not clear as to how the testing is to be performed for a synchronous condenser.
No
There is no technical justification supporting the 50 MVA criterion. Absent this, we propose to use the Compliance Registry criteria for generators of 20 MVA as a general criterion for data being verified for synchronous condensers over 20 MVA as well.
Yes
No
As we interpret the language, we do not agree with the 20% requirement. In the assessments performed in our area our goal is to use data that is much more accurate than what appears to be required under the standard. Allowing verification to be up to 20% inaccurate may result in inaccurate system assessments, potentially leading to overlooking potential system problems or to unnecessary system investment to address system concerns which are not really present. This value should be changed to a maximum of 5%.

No
No
The obligations set by this Standard are less stringent for Generator Owners/Operators than those contained in ISO-NE's Tariff. In addition, FERC's Standard Generation Interconnection Rules make clear that material changes to generation facilities (which would include changes to reactive power capabilities) must be reported to the Transmission Service Provider prior to the change being made. The Standard Drafting Team should consider whether language is appropriate to make clear that the Standard is not meant to displace obligations to report reactive power capabilities already contained in Transmission Service Providers' tariffs.
Yes
• Effective Dates: This proposal is not well explained and very well may not work. Some concerns that arise: (a) For those GOs that have units in multiple control areas, are they supposed to apply the Implementation Plan for their entire fleet or for their fleet on a per Region basis? This same issue can apply to TOs which may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Transmission Operator should be given the discretion to require and approve a test schedule within it's area. (b) For those GOs with only one or two facilities in a region, how will the 5-year implementation plan work? Will the GO with one facility in a region have 5 years to implement (i.e., the 100% rule would not "kick" in until 5 years out, or will the GO with one facility in a region have only 1 year to implement (since 20% of 1 unit would arguably capture the unit). • R1.2 and 2.2 All entities should use the same submittal form. Please delete the option for a Generator Owner to develop its own form. • R1.3… 90 days is too long for reporting data. Recommend 30 days for providing verification data. • VSL for R2 should mirror VSL for R1. Specifically R2 doesn't mention submitting >120 days as R1 does. • Attachment 1: 1. specify that the AVR must be in service and in automatic controlling voltage if required by the TOP 2. If AVR is not required by the TOP, does the unit still have to test? Under the VAR-001 standard an entity may be exempted by the Transmission Operator from having a functional AVR. Under such an exemption the need for testing should not be required. • Attachment 2: move the check boxes to the top so that that someone looking at form knows immediately what type of audit was performed. • There should be VSLs in regards to going more than 66 months between verifications. • Periodicity should be captured in Requirements, not in the Attachment • If each test is done on different days, does each test have its own verification date? • Please clarify what footnote 1 of Attachment 1 is intended to describe with "normal" with respect to the unit's normal expected maximum Real Power at the time of the verification. • Attachment 1, Section 2.1 states that during wind turbine and photovoltaic verification, 90% must be on line. This should read "with AT LEAST ninety percent of the…"
Yes
Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? This applicability criteria in this standard should be the same as the Compliance Registry requirements.
No
NERC is largely concerned with the declining frequency response of the Eastern Interconnection and this proposal seems completely at odds with that concern. The Planning Coordinator (or Transmission Planner) should definitely be allowed to request verification of selected governors. In addition to generators that have governor effect overridden by outer control loops (Distributed Control System, DCS) there may be a dead band within the governor. The Transmission Planner must be able to request verification of selected governor models that may fall outside of the standard. The question mentions Planning Coordinator but the standard itself is applicable to the Transmission Planner.
Yes
No

Yes
Requirement R4 is a direct violation of the Large Generator Interconnection portion of the ISO Tariff that requires generators to request permission and provide models prior to making changes to the equipment characteristics. As currently written, this appears to allow generators to submit models after making the changes. Such changes may have been detrimental to system performance and therefore need to be reviewed prior to implementation.
Yes
In requirement R2.1.1 what is meant by frequency excursion/reference change? This standard must require that all models provided are non-proprietary, otherwise a major reason (NERC MMG) for model collection will be undermined. This will prevent coordination of studies across regions which may undermine reliability. We are not sure if we have the correct version of draft MOD-027-1. In the “Differences also exist between MOD-026-1 and MOD-027-1” Section of this Comment Form, there are several mentions of Requirement R1 Part 1.x which we are unable to find in the draft standard. For example, Requirement R1 Part 1.2.1 in (5), R1 Part 1.3 in (6), R1 Part 1.4 in (7), and R1 Parts 1.1, 1.3, 1.4 in the “Compliance Elements for MOD-027-1” Section. Also, the referenced MOD-026-1 does not have the parts mentioned in this Comment Form. Is the background provided in this comment form incorrect, or are the posted versions of MOD-026 and MOD-027 out of date? In requirement R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by a many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping.
Yes
Yes, however the standard should not rewrite the Compliance Registry as attempted. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry’s wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity’s restoration plan. If the NERC standards become effective for non-material 9 MVA black start units those units will likely drop out of the program. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
Group
SERC Dynamics Review Sub-committee
Joe Spencer - SERC Bob Jones - DRS chair
Yes
Consolidating standards is beneficial
No
The DRS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
No
This provides all the information needed to allow the TO to rate the machines at whatever ambient temperature may be needed. Per #2, the DRS recommends that TO be changed to TP. In attachment

1 item 3.4, the DRS recommends that "correction factor" be changed to "adjustment method," to allow real power determination at multiple temperatures.
No
The use of sister units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability.
Yes
These 4 points should provide adequate testing of the generator. The DRS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Yes
Yes
Yes
Synchronous condensers supply reactive power to the grid. Therefore, the Transmission Planner needs to know a verified capability for the device.
No
A 50 MVA criteria for synchronous condensers is not in the standard. The standard says 20 MVA. However, a criteria of 75 MVA would be a more reasonable number. Units smaller than 75 MVA will have little impact to the reliability of the grid.
Yes
No
The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
The VSL for R2 is missing a needed component. The Severe category needs to include the following: "The Transmission Owner verified and recorded the Real and Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded." GO's should be required to provide expected values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. Item 3.4 in Attachment 1 refers to Transmission Owner. It should say Transmission Planner to match Requirements 1 & 2. Only one verification is needed for sister (identical) units. The standard currently requires verification for all units.
No
The DRS agrees that the intended generating units would be covered by reasonable interpretation of the applicability section 4.2. However, the DRS recommends that footnote 3 be changed to read "The common transmission voltage level bus (i.e. 100 kV or greater) to which the step up transformer(s) is connected." This more clearly includes "step up" transformers for some types of variable energy plants which may not be "generator step up" transformers.
Yes
Yes
We agree that it shouldn't be included. However, it appears that there is an error in the question. Synchronous condensers cannot be used to control frequency. Was this a "cut and paste" error from

MOD-026?
No
No
Yes
For Requirement R1, the SERC DRS recommends that the time be changed from 30 calendar days to 90 calendar days. Relative to the time allowed for accomplishing other requirements, there is no benefit for only allowing 30 days for requirement R1. 90 days would allow for more communications between the requesting Generator Owner, the providing Transmission Planner and other entities (such as the software vendor or turbine manufacturer) to coordinate obtaining the necessary items listed in requirement R1. Additionally, 90 days would be consistent with the “more than 90 days” VSL level for this requirement. Relative to R3, bullet three, this covers the situation where predicted response does not match recorded response for three or more events. We suggest this be one or more events because significant events are so rare in the eastern interconnection. Relative to the VSL for R2, the first paragraph in the “Severe column” has confusing words "failed to provide the verified models no more than 90 days late." We recommend changing the words to "provided more than 90 days late". In multiple locations in Attachment 1, 730 days seems to be an excessive amount of time from capturing an event to sending documentation to the TP. We recommend a period of 180 days. In two places in Attachment 1, excitation control system is referred to. Shouldn't this be turbine/ governor control system?
Individual
Dan Hansen
GenOn Energy
Yes
Yes
Yes
The intent of the question is not well understood. The answer is complicated by the inability to replicate the system condition that will demand the unit operating limits, creating artificial lower limits under the test conditions.
Yes

No
Yes
No
No
Disagree strongly: It is overreach to make this a generator protection standard; the standard is not comprehensive enough to take on that task. As a result, the SDT has overstated the purpose and intent of this standard. Simple is better and appropriate. Purpose: To improve reliability through coordination of generator protection systems with unit/facility voltage regulating limiter functions and protection.
Yes
Yes
In some ways, the requirements are too subjective in determining what protection and limiters are subject to coordination. In other ways, the standard provides insufficient or contradictory requirements in defining how coordination is achieved, even for well established protection practices. It is difficult to define all-inclusive coordination principles with so many variables in a simple straightforward standard. As written, the standard is a compliance risk to the applicable entities based upon future arbitrary and subjective interpretation by compliance organizations. Vivid examples are provided in Attachment 1. Loss-of-Excitation Zones 1 & 2 does not “coordinate” with the Steady State Stability Limit. In the diagram of the generator capability curve, SSSL is reached prior to the Loss-of-Excitation protection, contrary to R1.1.1, requiring the protection to operate ahead of the SSSL. Also, Loss-of-Excitation Zones 1 & 2 exceeds the generator capability curve, and does not fulfill R1.1.1 that requires protection to operate before conditions exceed equipment capabilities. Other variables with indirectly relationships are subject to future interpretation. A generator stator may have overvoltage protection set at 118% with a 2 second time delay, allowing it to meet PRC-024-1 ride through capability. Overvoltage protection also has a correlation to field current limiters. To insure and demonstrate absolute “coordination” with a field current limiter under all circumstances, it may be necessary to reduce the field current limit. The move will be counter productive to system performance in most transient conditions, but may be required to insure “coordination.” The SDT should make specific requirements of defined scope rather than broad, subjective, and open-ended requirements, i.e. 1) Volts/Hz limiters shall coordinate with Volts/Hz protection, 2) Under excitation limiters shall coordinate with steady state stability limits and loss-of-field protection, and 3) field current limiters shall coordinate with field current capability. The standard should exclude statements that the protection must operate before conditions exceed equipment capability. It will be difficult to provide definitive evidence of compliance for the use of many protection elements on older equipment with no documentation of equipment capability to withstand conditions such as Volts/Hz. If a generating unit is rated for +/- 5% terminal voltage, how is the generator’s overvoltage withstand capability demonstrated to PRC-024-1 criteria. In a compliance world of absolutes, Generator Owners may not be allowed to use general “rules of thumb” when coordinating protection. In ways that are

counterproductive to reliability and equipment protection, Generator Owners could end up removing protection elements when it cannot be demonstrated that it operates before the condition exceeds equipment capabilities. Calculation of the steady state stability limit requires the transmission system Thevenin equivalent impedance. Therefore, it is necessary for the standard to require Transmissions Owners to provide Generator Owners this impedance within 30 days of request. Likewise, the allocated time for Generator Owners to perform coordination studies should increase by 30 days or more to 120 days. In R1.2, a five year coordination study interval is an unnecessarily short duration for generating units without significant changes in the generator protection or an AVR replacement. A company with 150 generating units will average 2.5 coordination studies per month on a non-stop continuous rotation. Ten years is a more appropriate cycle for a coordination study on a unit with no changes. The wording used to trigger an examination should be specific and defined, rather than the ambiguous and nondescript statement of “changes that are expected to affect this coordination.” To meet compliance, it will be necessary to expend needless effort for the possible interpretations of “changes” that otherwise will have little or no impact for the intent or purpose of this standard. Suggest rewording R1.2, “Each Generator Owner or Transmission Owner shall verify the coordination indentified in Requirement R1 at least once every ten years or within 120 calendar days following modifications impacting coordination when the following activities occur: 1) a change in AVR limiters or AVR protection for over-excitation, underexcitation, Volts/Hertz, stator voltage, or field current, or 2) generator protection changes for stator voltage, loss-of-excitation, or Volts/Hertz protection.” For only 30 days of differences (90 to 120), VSLs expand from Lower to Severe. Considering the justifiable allowance for 20% of the fleet to go 5 years without demonstrated coordination, the logic for the acceleration of severity over such a short time duration is not understood.
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
No
Yes
No
PacifiCorp believes that the four points proposed by the SDT are adequate with respect to thermal and hydro generation units; however, the proposed points do not adequately take operating conditions for wind generation facilities into consideration.
No
First, PacifiCorp believes that over-excited reactive capability at rated Real Power verification should be performed on the same basis as for under-excited reactive capability and over-excited reactive capability at expected minimum Real Power output – that such data should be recorded as soon as a limit is reached. Second, this does not adequately take operating conditions for wind facilities into consideration.
Yes
Yes
Yes
Yes
Yes

No
No
Yes
Section 4.2 of proposed Standard MOD-025-2 contemplates the inclusion of large wind farms within the scope of the proposed standard, as it is applicable to generating units above individual and aggregate nameplate rating thresholds (as the commentary seems to indicate is intended). The specific requirements for verifying Real and Reactive Power capabilities, however, do not make any allowance for operating differences of wind generation units. If wind generating resources are to be included within the scope of this proposed standard, then the standard should include express allowances for verification methodologies that are applicable to wind generating units.
No
Yes
Yes
No
No
Yes
Section 4.2 of proposed Standard MOD-027-1 provides that units or plants with an average capacity factor greater than 5% over the last three calendar years, that also meet other characteristics, will be considered “applicable units.” However, the term “capacity factor” is not defined in proposed Standard MOD-027-1. Proposed Standard MOD-026-1, on the other hand, uses the term “Capacity Factor,” suggesting it is a defined term but without an accompanying definition in the NERC Glossary of Terms or otherwise. PacifiCorp believes that the Standards Drafting Teams should make the use of the term “capacity factor” consistent across all proposed standards and define the term as necessary for additional clarity.
Yes
Yes
Yes
Yes
No
Measure M1 in proposed Standard PRC-019-1 requires current evidence to satisfy the coordination requirements of Requirement R1, Section 1.1, plus one previous dated set of evidence demonstrating the latest coordination review has been performed within the intervals prescribed in Requirement R1, Section 1.2. The latter category of evidence may not be available immediately upon the effective date of this proposed standard. The implementation plan should clarify how this Measure will be addressed during the phased-in implementation schedule.
Yes
Yes
No

No
Group
NERC Staff
Mallory Huggins
Yes
No
Requirement R1, part 1.3 and Requirement R2, part 2.3 indicate that data is to be submitted to the Transmission Planner. We agree that the data should be submitted to the Transmission Planner, not the Transmission Owner. Further, we believe that the data should be provided to all entities that have need of the data, including the Transmission Operators and Reliability Coordinators who need the data for their operational planning and real-time models.
No
It is not necessary to specify a temperature for which submitted data should be adjusted because one temperature will not be appropriate for all regions or for all types of studies. Providing the recorded value and a temperature correction factor or correction table is appropriate.
No
While we agree that all units connected at voltage <100 kV need not be tested and modeled, any units >20 MVA and plants/facilities >75 MVA should be tested and modeled accurately regardless of interconnection voltage. The reliability impact of generating units is more directly related to unit capability than interconnection voltage.
No
Reactive Power capability is not a linear function of Real Power. The reactive capability curve and minimum excitation limiter settings for each machine should be used to determine the expected gross reactive capability.
No
Often, on larger units, temperatures do not stabilize within one hour. It is important for this test to assure that temperatures have stabilized and that the unit capability is sustainable, so the overexcited reactive capability test should be conducted for a minimum of two hours or until the temperatures have stabilized.
Yes
Yes
Although the penetration of synchronous condensers in North America is low, in most cases they are applied to address a reliability need, making it necessary to have accurate models of these devices for system studies. Although other devices may be outside the scope of this standard, accurate models are similarly necessary for devices such as static var compensators (SVCs) and static compensators (STATCOMs).
No
Section 4.2.1 indicates the standard is applicable to synchronous condensers greater than 20 MVA. We agree that the standard should be applicable to synchronous condensers greater than 20 MVA rather than 50 MVA.
Yes
No
We agree the standard should provide flexibility to the Generator Owner; however, the need for flexibility must be balanced against the need for valid models for system studies. Accuracy must be at least as stringent as required for market dispatch. When operational data cannot be verified within 5% of the expected value, an entity should be required to provide data based on staged testing.
No

No
Yes
The violation risk factors associated with Requirements R1 and R2 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 and R2 should include the operations planning horizon. The SDT should consider use of the word “verification” versus “validation” and assure that the term used in this standard is consistent with other standards.
No
We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
No
The standard should include a requirement that provides the Planning Coordinator the ability to request a review of any turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section. Accurate turbine-governor models can be critical to valid underfrequency load shedding assessments and other studies requiring accurate frequency response. This is particularly important for large units that operate infrequently, but are committed for critical operating conditions such as peak load or other times of capacity deficiency.
Yes
We agree that it is not necessary to validate synchronous condenser models in MOD-027 since synchronous condensers do not provide frequency response. However, the discussion supporting this question refers to verification of excitation control systems. Validation of synchronous condenser excitation control systems should be required in MOD-026.
No
No
Yes
It is not possible to accurately model system frequency response with valid models for only 80% of the installed system capacity. System frequency perturbations are experienced by and responded to by all frequency responsive generators, regardless of interconnection voltage. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per SDT estimates, this will assure accurate modeling for approximately 95% of installed capacity. The interconnection voltage is not relevant to frequency response and should not be a condition for applicability. We also disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions giving them lower capacity factors. However, those will also be the units loaded at lower levels, making them the units with head-room to respond, thereby making them critical to frequency response during those conditions. They may be of a lower priority in the implementation plan. The violation risk factors associated with Requirements R1 through R5 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R5 should include the operations planning horizon. In Requirement R2, part 2.1.1, it appears the comparison should be between recorded response and simulated modeled response rather than between on-line response and recorded response. Further clarification is necessary. In Requirement R4, when the

turbine/governor and load control or active power/frequency control system are modified as part of a planned project, the Generator Owner should be required to provide a revised model prior to placing the revised equipment back in service. In Requirement R5, part 5.2, the reference to negligible transients is not measurable. We recommend modifying this to ". . . results in a response that varies less than the numerical stability of the program used for the simulation." In Requirement R5, part 5.3, the introductory phrase "For an otherwise stable simulation" is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with "A disturbance simulation results in . . ." The SDT should consider use of the word "verification" versus "validation" and assure that the term used in this standard is consistent with other standards. Validation of models only every 10 years is far too long a period. Models should be calibrated as often as possible, preferably with every significant system frequency disturbance. Experience in the WECC region has shown that validation by observation against system events yields more accurate model performance than relying on a single staged test because the events provide for a wide variety of system conditions for the comparison. The background material suggests that more frequent validation against frequency events is impractical because of the scarcity of events. That is incorrect; there are several frequency events each year in all of the interconnections where frequency deviates beyond the short-term trigger limits set forth by the Resources Subcommittee, which indicate that generators should have exceeded the traditional deadband of ±36 mHz and responded. The initial completion of validation for all applicable units should be within 5 years, not 10 years. The 10 year time is excessive. Validation or calibration after a measured system event should occur within 6 to 9 months of the event, not 2 years. Experience in the WECC regions shows this to be sufficient and achievable.
Yes
No
The posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. We agree with the 20 MVA threshold in the posted standard.
Yes
Devices such as static var compensators (SVCs) and static compensators (STATCOMs) have equipment limitations, control systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser. Also, the standard must remain neutral as to the type of reactive resource, allowing for other technologies such as storage and demand-side regulation through electronically coupled loads that are relied upon for reliability purposes in the same vain as other reactive sources cited.
Yes
No
As written, the standard only addresses 80% compliance on generation and reactive sources that are not subject to regulatory approval. It appears that a section 5.2.5, similar to section 5.1.5, is missing from the Effective Dates section.
No
The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency. Further, Section G should address the system concerns described in Table 2 of the SPCS Technical Reference Document "Power Plant and Transmission System Protection Coordination," for the generator protection functions that must be coordinated.
Yes
No
Yes
The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the

generating unit, such as the list in Section G.This should be consistent with protection coordination described in the SPCS Technical Reference “Power Plant and Transmission System Protection Coordination.” Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions. Requirement R1, part 1.1.1: The standard emphasizes preventing tripping of generating units and generating facilities due to miscoordination. Another aspect of coordination is to coordinate the protections and controls to coordinate with the equipment capability. Without guidance or direction, the standard could have the unintended consequence of overly conservative settings that limit the ability of the facilities to respond to system disturbances, or inadvertently create a common-mode failure trip point across a generation fleet. Requirement R1, part 1.1.2: The word “check” is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as “Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment.” Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project, the Generator Owner or Transmission Owner should be required to verify coordination PRIOR to placing the revised equipment or settings back in-service. It is important to note that protection setting changes on the transmission system may necessitate generating unit protection setting changes which in turn require a review of coordination with the generating unit or plant voltage regulating controls. While coordination between the transmission system and generating unit protection settings is outside the scope of this standard it is important that this coordination is required by in a reliability standard. The examples emphasize steady-state limits and capability curves without mention of the short-term generating unit capabilities. Proper coordination should also apply to transient response of the generating unit and its associated limiters to meet the reliability objective of this standard. Focusing examples on steady-state coordination may be misleading and result in miscoordination for transient events. Of particular concern is the transient response of exciters in field-forcing during system disturbances; loss of reactive support from generation during such events can be catastrophic and lead to cascading. The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.
Individual
Joe Petaski
Manitoba Hydro
Yes
Yes
Yes
The standard should allow the provision of ambient temperature during the verification be provided to the Transmission Owner as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature if needed OR Real Power data submitted be temperature adjusted to some other than ambient temperature as requested by the TO.
Yes
The Applicability of this standard should be to BES Generating Units and Facilities. Section 4.2 should not restate components of the proposed BES definition.
Yes
No
To obtain more realistic rated real power and over-excited reactive power ratings, the minimum

verification time should be 2 hours or until temperatures have stabilized. For under-excitation, the test duration should be 1 hour.
Yes
Yes
To cover all configurations, the standard should also include and stipulate that synchronous machines that operate as generators at some times and as synchronous condensers at other times must perform a reactive capability test in each operating mode. This may be covered in Applicability 4.2.1 however the current wording should be modified to make this clear.
No
The 50MVA criteria in question 9 does not appear in the draft standard (only in the implementation plan). If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.
Yes
Yes
No
Yes
A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
No
No
Yes
Yes
-MOD-027-1 cannot be applicable to units dedicated as synchronous condensers since such units do not have turbine/governor and load control or active power/frequency control functionality installed. For generator units which can be operated as synchronous condensers MOD-027-1 already includes such units therefore reference to synchronous condenser operation is not necessary.
No
Yes
A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
Yes
-MH disagrees with the SDT's assumption that the majority of turbine/governor and load control functions will be verified through ambient monitoring. If both turbine/governor and load control functions as well as excitation control functions are to be verified through staged tests then having different effective dates for MOD-027-1 and MOD-026-1 introduces an unacceptable level of

complication in testing and documentation. MH recommends that the effective dates for both standards be identical and that MOD-026-1 effective dates be applied to MOD-027-1 to accommodate entities which will utilize more ambient monitoring than staged tests. -The SDT provides no information regarding testing and model verification which was completed under the regional guidelines (such as the MRO Generator Testing Guidelines) and the previous versions of the generator verification standards and which comply with the current version of the standard. With the amount of effort and costs which went into this exercise, MH proposes that such compliance information be accepted if completed within the past 10 years of regulatory approval of the proposed standards. Entities should not be penalized for lengthy SDT delays in developing these proposed standards. -For Section 4.2 “Facilities”, the section should refer to ‘BES Generating Units and Facilities’ instead of restating components of the proposed BES definition.
Yes
No
The 50MVA criteria in question 2 does not appear in the draft standard. If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.
No
Static VAr compensators do not belong in a generation standard.
Yes
No
-MH recommends that the effective dates for this standard be identical to MOD-026. This will allow entities to schedule all work and required outages simultaneously.
Yes
Yes
No
Yes
-The standard should take into account generating units whose capacity is determined based upon the run of the river where it may be difficult to test at design capacity. We suggest that an engineering methodology/calculation be acceptable for these units. -Wind generation should be excluded from the applicability of this standard or a calculation should be allowed due to the difficulty in testing wind units. -The SDT provides no information regarding testing which was completed under the regional guidelines (such as the MRO Generator Testing Guidelines) and the previous versions of the generator verification standards and which comply with the current version of the standard. With the amount of effort and costs which went into this exercise, MH proposes that such compliance information be accepted if completed within the past 5 years of regulatory approval of the proposed standards. Entities should not be penalized for lengthy SDT delays in developing these proposed standards. -The Applicability of this standard should be to BES Generating Units and Facilities. Section 4.2 should not restate components of the proposed BES definition.
Individual
Greg Rowland
Duke Energy
Yes
Yes, however need to define "Rated Real Power" so that entities are using a consistent basis for data reporting. MW validation is intrinsically connected to governor response issues and thus should be instead be combined with MOD-27 frequency response efforts and the following modelling parameters

defined and addressed: – Pmax • The continuous operating limit • The ultimate max emergency output. • Should there consider weather conditions (summer or winter, etc.). • PMAX associated with Transient stability – is it the same as for LF • Is this on the order of 105% or 110% or ??% of normal max loading Please clarify if real and reactive verification can be performed at different times.
No
The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data. Both the TPs and Transmissions Operations entities need to have accurate model information and the Operating studies are much more critical for BES reliability.
No
System models are used for reliability purposes beyond planning purposes, which are at best, an educated guess at what the system will look like out in the future. The real time and day ahead models are most significant for assuring reliable system operation. It would seem that if the TP needs model data different than the Transmission Operations needs, the 1st step is for them to define a technical basis for that data. Once that is done, then the GO/GOPs can develop numbers that match those conditions. Pmax will vary on ambient temp for some types of generation, lake temps for other types and hydo conditions for those units. Without a defintion of the data based on the studies to be performed, all the GO can do is guess. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.
No
Obviously, all units which are critical to reliability should be included, but what is critical is dependent upon system configurations. The continent wide standard should specify the largest size units critical in an interconnection and then regional standards might tighten the number based on that region's need. The SERC region currently requires real & reactive verification only for units > 75 MVA (RFC uses 85 MVA). The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentialy identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).
Yes
We agree that four points are sufficient to provide a straight line approximation over a unit's operating range at points from Pmax and below, but additional consideration is needed for operation above Pmax. We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." The lagging capability curves have a break at rated pf. Trying to represent that with a single line with end point at Pmin and Pmax would eliminate a large portion of the available capability curve around rated pf. The leading capability might be more reasonably estimated by a linear assumption. Technically, nuclear units are base load plants as are some very large coal units and thus would not be expected to operate for any significant period of time at pmin, thus the term base load is more appropriate than nuclear for excluding testing at Pmin First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary."
Yes
Provided that the verification is accomplished through staged testing or through operational data review and a unit is capable of reaching the expected over excited capability, 1 hour should be adequate to determine if equipment temps that might limit capability are stabilized. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this

proposal in comments to Question 14).
Yes
We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit (Graphic has been provided to the SDT). There needs to be standards on how model values are selected, such as, • The lagging capabilitiy values should be based on 90% of gross generator capability at minimum normal Hydrogen pressure minus aux system loads and xfmr losses • The leading capability values being modeled should be based on (UEL limiter setpoints as documented by PRC-19 coordination is probably appropriate).
Yes
No
As the draft is currently written, these two methods are understood to be allowed, but experience has shown may not be able to fully validate the available capabilites. We believe engineering analysis could be used in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. The answer may be to test or operate as far as you can based on system voltage and then evaluate margin to unit thermal limts (Generator, Bus, GSUs, etc) and determine if you could reasonably have reached full capability if system conditions warrented the need.
No
We have model validation requirements but no definitions to what we are needing to validate to. The "expected value" is not clearly defined, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference our response to Question #10.
Yes
There have historically been regional differences in unit criticality size.
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) MVAR validation issues should be combined with generation FAC-8 issues to eliminate confusion that these seperate standards have caused. 3) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 4) We suggest revising Requirements R1.3 and R2.3. Data should be submitted to the TP at the next annual update provided on MOD-010 model data. 5) Revise attachement 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 6) It is noted that MOD-11 which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliablity purpose intended. 7) Since GO/GOPs do not always

model electrical systems, nor participate in interconnected system models groups such as the Master Model Working Group (MMWG), there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF is considering a collaboration to do so.
No
We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action.
Yes
Yes
Not sure why this question is in the CF, other than it was accidently copied from the MOD-26 CF? Synchronous condendors are MVAR devices not MW devices and thus should be covered by MOD-26, not 27, if their dynamic response is signficant to grid reliability. Since they are typically applied in weak spots of the transmission system, it's difficult to believe they would not be critical by their presence.
No
No
Yes
1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don’t match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. 8) The frequency response of a generation unit is intrinsically connected to the Pmax values used in various system models (old MOD-24). These 2 validation efforts should be connected and the following modeling parameters defined and addressed: Pmax • The continuous operating limit • The ultimate max emergency output. • Should there consider weather conditions (summer or winter, etc.). • PMAX associated with Transient stability – is it the same as for LF • Is this on the order of 105% or 110% or ??% of normal max loading A graphic illustrating this point has been provided to the SDT.
No
See response to Question #2 below.
No
We feel that this standard is not applicable for solar facilities or induction type generators used in some wind farms. Several different exemption criteria are specified in the various GVSDT standards. We understand the distinction made for MOD-26/27 (100MVA) from the MOD-25 criteria (75MVA). The standard likely should be consistent with one or the other, rather than having a 3rd criteria (50MVA). For this standard, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit,

15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units ≤ 75MVA may be identified by a transmission entity as critical for BES reliability. Regional criteria are allowed to address these concerns to make requirements applicable to such units identified as critical for BES reliability in that region.
No
See the purpose of the standard. It's not clear why a generation protection/control coordination requirement would be applicable to non-generation resources, other than maybe synchronous condensors.
Yes
Yes
Yes
No
Electronic documentation of coordination efforts should be considered accecptible as long as a revision history is maintained. Past history is not significant to present/future reliability. Only the presentation documentation of coordinations is needed along with proof that the results have been implemented. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
Yes
There may be regional variations in regional critical size criteria.
Yes
1) In several places in the posting documents there is a discrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 2) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 3) Section 5.2.5 is missing from effective date in the draft standard. 4) R1.1.1.1 seems to infer that the 40 relays should be set inside the Capability curves and the SSSL. The 40 relay should be set inside the SSSL but may be outside the capability curves as it is intended to prevent a pole slip. AVR protective functions may be set to protect the capability curves.
Individual
Eric Ruskamp
Lincoln Electric System
Yes
Yes, but the verification periods should be different for Real and Reactive Power. It is not unreasonable to expect a Real Power verification test on an annual basis, as this data is usually available annually at some time when the unit is operated to serve load. It states the purpose of the Project 2007-09 Generator Verification is: “To ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.” Without annual operation to verify Real Power it appears difficult to ensure this objective with a high degree of confidence.
Yes
The Real Power Data should be adjusted based on temperature to indicate what the output for the generating unit would be for peak summer conditions for a summer peaking utility and peak winter conditions for a winter peaking utility. Humidity is also factor that affects the output of units with evaporative cooling as well as the performance of cooling towers. Previously as part of the Mid-continent Area Power Pool our utility was required to submit monthly capacity accreditation of the generating units that was adjusted based on the ten-year average of the high temperature for the peak load day of the month. For the summer months this provided a fairly accurate estimate of the

actual generating capabilities of the unit in the summer months. In the winter using the high temperature for the peak day was not quite as accurate, since the peak on the winter day does not usually coincide with the peak temperature for the day, but the ambient high temperature on these days is usually quite low. Even in the shorter months the output data may be beneficial to the Transmission Planner when large units in a region are out for maintenance. It is questionable as to how easy it would be for the Transmission Owner to apply the correction factors to other ambient temperatures if they are only given the temperature at the time of verification test. For gas turbine units without some form of inlet cooling the output may vary by as much as 30 percent from summer to winter ambient conditions. This is a significant amount of generating capacity.
No
The definition of “expected value” needs to be more clearly defined as it is somewhat unclear. The verification should probably be within at least 5% of the expected output of the generating unit for a given ambient temperature, rather than 20% as stated in this draft. For a simple-cycle gas turbine the real power output for the verification test would in most cases be greater than what it would be for summer peak conditions due to the higher generator output that typically occurs with these units as the turbine inlet temperature decreases. It is usually desirable to test the unit with the same conditions that the unit will be most needed. For summer peaking utilities this would be with reasonably high ambient conditions. When only recording real power data it is usually not that difficult to recordthe data in the summer when the units are already operating to serve the load. The coordination to record reactive power data at this time may be more difficult.
Yes
Under the Applicability Section, 4.2 Facilities, the “applicable units” are stated to have an average capacity factor greater than 5% over the last three calendar years and that the “majority of industry agreed with the standard MOD-026-1 5% capacity factor threshold” (Background Information: “Standard MOD-027-1” - #3). LES is concerned that the industry builds power flow models for future summer peak conditions, and therefore, LES is not convinced that the capacity factor threshold of less than 5% is a good indication of what units are on-line in these future models. Therefore, the goal for verification of the dynamic models associated with 80% or greater of the connected MVA per Interconnection may not be achieved. LES believes that a check (i.e., survey) of the ERAG MMWG models would be a good indication of whether or not the capacity factor threshold satisfies this objective.

Individual
Jose H Escamilla
CPS Energy
No
The Transmission Planner is the appropriate entity to use the data.
Yes
Generator owner should perform the correction and determine the temperature value.
Yes
Yes
No
30 minutes should be sufficient time to verify capability.
Yes
Yes
Group
Public Service Enterprise Group
John Seelke
Yes
No
MOD-025-2 requires that data be submitted by GOs or TOs to their respective Transmission Planner

(R2.3). It should not require that it be submitted to the Transmission Owner as the TO has no need for this data.
Yes
We believe that the Real Power data submitted should be corrected to a temperature specified by the entity that requires the verification of Real Power capability. That entity is probably the Resource Planner or the Planning Coordinator– see the Functional Model, version 5 posted at http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf. For Generation Owners that belong to Regional Transmission organization that has a reserve margin criterion, it is probably registered as a Resource Planner and Planning Coordinator. For example, PJM, NYISO, and ISO-NE are each registered as a Resource Planner and a Planning Coordinator.
Yes
No
For clarification, Attachment 1, paragraph 2.2 does not require Reactive Power capability verification for wind and photovoltaic at minimum Real Power output. It also appears that Nuclear Units are also exempt. “Nuclear Units” has the term “Units” capitalized, but it is not in the NERC Glossary and should probably be lower case. We suggest that R2.2 be redrafted as follows: “Verify Reactive Power capability of all generating units other than nuclear, wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. In addition, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. This would require a change in paragraph 2.1 For other units, these points are acceptable.
Yes
The drafting team should provide the rationale for the one hour minimum for over-excited reactive capability.
Yes
This documents the system conditions and unit conditions when limits are reached.
Yes
A 50 MVA minimum size for synchronous condensers was not found in the proposed standard – see paragraph 4.2.1 which has a 20 MVA minimum. Whether the limit was intended to be 50 MVA or the 20 MVA limit stated in the draft, the SDT should provide a justification of basis for that MVA threshold. The impact that such smaller units would have on the BES is not substantial enough to justify requiring their inclusion in this standard.
Yes
No
Attachment 1 is unclear as to the implementation of the 20% requirement. Paragraph 2 states “Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:” As written, it appears that the 20% only applies to operational data “within the year prior to the verification date.” Does the 20% apply also to staged tests? If not, why not? Paragraph 5.2 in Attachment 1, regarding operational tests, is also relevant: “If data for different points is recorded on different days, the Generator Owner shall designate one of the dates as the verification date, and report that date as the verification date on MOD-025- Attachment 2 for periodicity purposes.” Is the SDT proposing to comingle operational data from one-year prior to the verification date as long as it is within 20% of the expected value? If so, what value would be reported – the test data that may be up to 20% higher or lower than the expected value or the expected value?
No
Yes

We have listed several concerns and questions below: a. We believe that Reactive Power capability at minimum Real Power output needs to be verified when a unit is installed and only verified thereafter when the generator itself is modified. Performing such tests will be difficult to run due to system voltage limitations at minimum Real Power generator output. This would require a modification or Attachment 1, paragraph 2.2, and paragraph 5. b. For the VSL's for requirement R2, the last paragraph of a Severe VSL should be modified as follows: "The TO verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded." c. The comments below reference Attachment 1. i. Paragraph 2 and its subparts would be more easily understandable if companion tables were provided that summarized the information. At last two tables would be helpful – one for traditional dispatchable resources and one for variable resources. ii. In paragraph 3, whether the verification is staged or operational should be provided. iii. In paragraph 3.2, the requirement to supply the voltage schedule provided by the Transmission Operator would not appear to be applicable for a staged test. Trying to test Reactive Power limits while maintaining a prescribed voltage schedule in not practical.
No
Yes
Yes
No
No
Yes
Nuclear units are often prohibited by their NRC licenses from having their governors engaged for frequency response. Since the Purpose of the standard is to "accurately represent generator unit real power response to system frequency," nuclear units with the restriction described above will have no response. These units should be explicitly exempted from the standard in the Applicability section.
Yes
No
The question and the standard contradict each other. The standard states that it applies to "synchronous condensers > 20 MVA" not "rated > 50 MVA. We do not agree with the threshold MVA applicability for generators. Field testing and industry history do not warrant the need for such a low MVA threshold. We suggest that the threshold be for larger units (rated > 500 MVA) that have the ability to significantly impact BES reliability. The resources required to apply this standard to smaller units compares to the benefits to the BES and the GO are generally not justified in most regions. However, it can be argued that smaller units can have a significant impact on the BES, especially in weak systems. Therefore, we recommend that an inclusion criteria be developed that would require units in such regions to be included.
No
First, the inclusion of "variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites)" was not noted in the standard. Second, we do not believe that including other static reactive resources that are not located at generating sites would materially impact reliability
Yes
Yes
Yes

Yes
Yes
Yes
The SDT should review R1. As it reads now, the phrasing of the first paragraph makes it difficult to understand what equipment is included for generator units and what is included for synchronous condensers.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We support this approach. The real and reactive power capabilities are related and hence having them addressed in one standard would enhance verification efficiency.
No
(1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”, we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.”, or be revised to: “To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”.
No
(1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator’s real power capability to reflect a difference in ambient temperature. If anyone, it should be the Generator Owner. (2) There seems to be little value in reporting the ambient temperature for the purpose of making adjustments to measured Real Power capability since it is only one of the several factors that could affect the real power output of a generator. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome,and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.
No
The Applicability section is not clear enough to expect consistent application. When the facility that makes the connection at 100 kV or above is not owned by the Generator Owner (e.g. a Distribution Provider might own this facility) the present expression of the standard will lead to inconsistencies. Facilities with identical electrical characteristics may or may not be subject to this standard only because of the structure of the ownership of assets. To address this, we propose revising section 4.2

by removing the condition for interconnection at 100 kV and above and aligning with the standard's purpose: 4.2.1 Individual generating unit or synchronous condenser > 20 MVA (gross nameplate rating) considered in BES reliability assessments.. 4.2.2 Generating plant/Facility > 75 MVA (gross aggregate nameplate rating) considered in BES reliability assessments. 4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.
No
One of the purposes of Project 2007-09 is to ensure that generator models accurately reflect the generator's capabilities and operating characteristics. To achieve this, it is important that at least the minimum data requirements of entities that require these data are satisfied. This includes verifying the generating unit's capability curve or at least that portion of the curve between its minimum and maximum real power capability. We therefore recommend including a new bullet 2.3 in MOD-025 Attachment 1 similar to bullet 2.1 that requires verification of Real and Reactive Power capability of all generating units at maximum over-excited and under-excited reactive capability at maximum gross Real Power capability (PMAX) where this is different from the generating unit's rated gross Real Power capability. The additional data points provided by this measurement (i.e. Qmax and Qmin at PMAX) will allow for a more complete verification of the generating unit's capability curve. Footnote 1 of MOD-025 Attachment 1 seems to use "rated gross Real Power" and "maximum [gross] Real Power" interchangeably. In general these two ratings may be different. We suggest deleting the footnote.
Yes
Yes
Yes
The standard should also be applicable to static var compensators and similar equipment used in reliability assessments of the BES.
No
There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Yes
No
We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: "Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" We interpret that the "IT" refers to the operational data. As such, we do not understand the "within 20% of the expected value". Does it mean the generator's real power output during the period from which operational data was collected must be within 20% of the generator's declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity. As written, we are unable to comment on the acceptability of the 20%.
No
No
Yes
In our previous comments, we raised a concern over the detailed requirements in Attachment 1 which in our view are overly prescriptive. Specifically, the requirements listed in Item 3 of Attachment 1 are too detailed, and some of the items listed in 3.1 to 3.6 are not needed or relevant to the provision of verified data for modeling or BES reliability assessment, but they create unnecessary administrative burden. For example, what would be the use of voltage at the high side of the generator step-up and/or system interconnection transformer(s) and the tap settings of these transformers in the application of the recorded real and reactive capabilities to modeling and reliability assessments? And what would be the required actions if the voltage levels and/or the transformer tap setting in the loadflow model or in real time are different from the reported values? Imposing the reporting requirement without a clear statement of the intended use, with justification, is unnecessary and

should be dropped. Further, we request clarification regarding the phrase “at the end of the verification period” in 3.1 and 3.3? Does it mean the time when the verification test ends, i.e. at the end of the 1-hour period referred to in Attachment 1, bullet 2.3? If the verification is provided by operational data, what would constitute “the end of the verification period”? We believe Attachment 1 needs only to specify the sustainability (Items 1 and 2) and the periodicity (Item 5). We also respectfully disagree with the SDT’s response to our previous comments on Attachment 1. The SDT’s view that (excerpt from Comment Report) “The SDT believes that attachment one does not contain requirements but provides clarity to the Requirements of the Standard.” is incorrect since it is clearly indicated in Requirement 1.1 to “Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.” According to the general rule for NERC standards, an attachment is a part of the standard that must be complied with, and hence any items contained in an attachment are mandatory requirements. With that understanding and with the way Attachment 1 is included in Requirement 1.1 that the items in Attachment 1 are not there for clarity but are requirements that must be complied with, we urge the SDT to remove the entire Item 3 from Attachment 1 as the information required in that item does not add to the intended use of the verified data. We do not have the same concern over Attachment 2 since it is made clear in Requirement 2.2 and in the Attachment itself that use of other forms is acceptable and hence use of the diagram is not mandatory. In Attachment 1, step 2.4 seems to be inconsistent. For the over-excited check, record should be taken at min. and max. real power output (i.e. it should state... data required in 2.1 and 2.2.) The table in Attachment 2 should be improved to match data to be recorded in Attachment 1 (i.e. there should be two columns for MVAR to record lagging and leading reactive power for a given MW). MOD-025 Attachment 1 bullets 2.1 and 2.2 should stipulate that Generator Owners and Transmission Owners conduct verification at generator terminal voltages as close as possible to rated terminal voltage. Finally, the standard should use SI units (e.g. active power not real power, Mvar not MVAR).
No
No, we are not aware of any, but the Applicability Section of the draft standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the “generating units” suffice to generally include all types of energy resources?
No
We do not agree with this approach. Currently, the applicability threshold of nameplate rating greater that 100MVA is too high. The combined performance of many units smaller than the threshold identified in the applicability section will have a material effect on the system frequency response. Even if the standard leads to the provision of useable model to the Transmission Planner for the applicable generating units, without sufficient good models, it might not be possible to meet the goals of accurately represent generating unit active power response to system frequency variations and predicting system frequency response to contingencies. We repeat the concern we expressed in our comments to MOD-025-2 related to the applicability criteria “connected at the point of interconnection at greater than 100 kV.” This condition will lead to the exclusion of units that are material in dynamic simulations and to which the applicability should extend. Also, we wonder whether the inclusion of Planning Coordinator in the question is a typo or the standard is missing the Planning Coordinator as an applicable entity. Please clarify.
Yes
No
No
Yes
We do not agree with some of the requirements. i. R1: Standards should stipulate the “what’s” not the ”how’s”. To avoid the perception that the requirement is prescribing the “how”, we suggest simplifying the language of Requirement R1 by replacing “Instruction on how to obtain” with “Instructions for obtaining”. Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be

complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process. ii. R2.1: The phrase “models acceptable to its Transmission Planner” begs the question on what is deemed acceptable and what if the GO disagrees with the TP’s determination. To address the two issues, we suggest adding a requirement for the TP to specify the models (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to “in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). Another possibility would be to remove this phrase altogether since the Transmission Planner would in any case have to declare the model “useable” pursuant to Requirement R5. iii. R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable. iv. We decide not to comment on the Measures and other compliance elements at this time in view of the comments, above.
Yes
No
There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
No
The SVCs serve quite different purpose and react to system conditions quite differently compared to their generator/synchronous condenser counterparts. Further, SVCs do not “trip”, per se, they vary their reactive outputs including going to and crossing 0 MVar and hence some of the interactions between the device and its protection systems in the case of generators/synchronous condensers are not applicable to SVCs.
Yes
We do not have any real issues with the purpose statement; however, we offer an alternative to add a bit more positive spin (as opposed to preventing tripping): To improve the reliability of the Bulk Electric System by ensuring proper coordination of generating unit/facility voltage regulating controls and limit functions with generator capabilities and protection system settings.
No
We interpret the wording “shall retain the latest and the prior evidence of compliance with Requirement R1, Measure M1” to mean the evidence for the last and the one before last compliance assessments. We question the need to keep the two sets of evidence. Keeping only the evidence for the last compliance assessment would suffice.
No
Yes
1. The standard introduces a local definition: “in-service”, that is subject to interpretation. Does “in-service” mean: - Installed but may or may not be put to service (e.g. mothballed)? - Installed and can be put to service at any time? - Installed and on-line? Generators/synchronous condensers will have a reliability impact only when they are connected to the grid (put on-line). However, the timing of these facilities to be put on-line is at the discretion of the GOs and perhaps under some conditions specified by other entities such as the TOP or RC. It is thus conceivable that installed facilities can be

put on-line at any time. To ensure proper reliability performance, we suggest to change “in-service” to “installed” to make sure the facilities meet the standard requirements if and when they are put on-line. 2. R1.2: The wording: “verify the existence of the coordination” does not drive home the intent of ensuring the settings are coordinated and reviewed once every 5 years or as changes occur. We suggest to change R1.2 to read: “shall review and revise as necessary the coordinated settings identified in Requirement R1 at least once every five years or within….”
Individual
Karen Alford
Gainesville Regional Utilities
Yes
Yes
No
Yes
Yes
No
We suggest 30 minutes. While it may take an hour to reach full stabalized temperatures the probablity of being called to peform form greater than 30 minutes is remote.
Yes
Yes
Yes
Yes
Yes
What is defined as the "expected value?"
No
No
No
No
Yes
Yes
No
No
No

Yes
Yes
No
Yes
Yes
Yes
No
No
Individual
Kirit Shah
Ameren
Yes
No
Both the Transmission Owner and Transmission Planner should receive it.
Yes
The ambient temperature at which the testing is performed would be an important data item. Because of greater familiarity with the equipment and its capabilities, any temperature adjustment to arrive at a different specified real power value should be performed by the Generator Owner. The Transmission Owner/Transmission Planner, who would be performing system modeling and study work, would be the entity most appropriate to specify temperature values for which temperature adjustment factors would be determined. Capabilities at different ambient temperatures need to be provided to meet the modeling requirements of the MMWG, and that the GO and TO should agree on what ambient temperatures to assume for the temperature adjustment.
No
The allowance for exemption of sister units should be permitted. Only one verification for sister units should be required. Testing for units less than 75 MVA should not be required, as these have little impact on grid reliability.
No
While the testing regimen for the generator owners should not be made unduly burdensome, the four point test, if used to provide a straight line approximation of the generator capability, could result in somewhat more conservative reactive power operating limits for other real power levels as compared to a generating unit’s published capability curve. The accuracy of the straight line approximation would vary on a generator-by-generator basis.
Yes
No
(1) From transmission perspective: If a plant limit is encountered in the testing, and it is a hard limit not to be exceeded, then the capability at this limit should be recorded. If a limit is identified on the transmission system such that the testing cannot be completed, then the capability should be noted but this would not be a firm limit. (2) From GO perspective : Our testing people won't know if the

transmission system is causing the limit because they aren't allowed to "see" the transmission system. Second, they are not allowed to test at time of seasonal peak because their testing may jeopardize the availability of the unit and testing during the fall and spring will mean higher voltages and frequently some type of testing limit is reached. Engineering calculations and justification should be allowed. Finally, we thought the 20% "margin" was to allow for these unavoidable risk restraints on testing the units. If a plant limit is encountered in the testing, then the capability at this limit should be recorded. However, it is unclear how this data, and the 20% margin, should be used in the verification process. We request the SDT clarify how data readings within the 20% margin should be used to determine the Real and Reactive capabilities of a generator or plant.
Yes
No
The size of synchronous condensers to be verified should be consistent with generator sizes which need to be verified. Testing for units less than 75 MVA should not be required.
No
While these two methods are acceptable, there is not enough flexibility included to allow for engineering support if necessary.
No
While the 20% margin is appropriate and appreciated, it is unclear if verifying the output of a generator at 80% of real rated output will satisfy regulator rating requirements at the time of seasonal peak. Thus, from the user of this data (e.g. planners), this % is too great. From the generator owner and testing personnel , this % makes sense and seems appropriate. We would suggest the SDT provide basis for this % and a guidance how it should be used for all conditions.
No
Yes
There may be a conflict with MISO Module E as it relates to duration of the testing, e.g. one hour versus longer than hour duration.
Yes
(1)If a demonstrated value is less than the corresponding expected value, then the generator owner should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Owners for system modeling use. (2) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (3) We understand the 20% and 10% variances allowed in the draft are for testing purposes. However, it's unclear how they should be used. For example, are they relative to the results at time of seasonal peak, or just maximum output at the time of testing? (4) Notes 1 and 2 should be Requirements. It is difficult to determine how compliance with footnotes will be audited. (5) Engineering judgement should be clearly allowed when meter data (for example no meter at the high side of a GSU), auxiliary data, etc. is not available as required in Attachment 1. (6) Sister Unit exemptions should be allowed for generators that are essentially identical and operated in an identical fashion.
No
Yes
Yes
The question does not appear to be worded correctly. Draft Standard MOD-027-1 deals with turbine/governor and load control, rather than excitation control systems.
Yes
(1) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (2) R4 of the Draft references footnote

5. It appears this footnote is overly broad and requires editing to precisely identify equipment systems that can truly impact system reliability. This footnote should be edited so it becomes either a new Requirement or a new set of sub-requirements. No other systems should be included.
Yes
Yes
Yes
Question should be directed at transmission planners. I would believe the static VAr compensators are required for system voltage support, similar to synchronous condenser or generation.
Yes
Yes
Yes, only if settings need to be verified. No if testing needs to be done to verify settings.
No
(1)Volts per hertz and stator overvoltage protection are more applicable during unit start-up, not running conditions, where the system maintains the voltage and frequency. These should be eliminated. (2) The standard needs to be clear on what relay elements need to be included if enabled. (3) The standard needs to be clear on how to plot the diagrams to incorporate operating voltage. For example the generation is most stable while maintaining maximum permissible voltage and producing the most VAr's possible. Therefore should the plot be at maximum voltage of 1.05pu. (4) It would be helpful to have some reference for where the development of the Steady State Stability Limit equations in the draft standard could be found. None could be found on the NERC website. We are concerned that the method proposed for calculating steady state stability limits does not include sufficient conservatism.
No
Retaining studies for 10 years seems unreasonable and could lead to confusion. Retaining data from previous audit seems reasonable to assure studies are being done every 5 years. Regarding R1.1.2, in order to limit the need to take unnecessary outages, which may be required to verifying settings, verification of settings should be limited to a one time only, upon installation or setting change.
No
Yes
(1) Standard needs to be more specific and clear on what evidence is need for 1.1.2. (2) Violation Severity Levels seem arbitrary and need to be reviewed, considering the standard is giving four years to be 100% complete. The system is presently operating with few if any miss-coordination on these protection systems. (3) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (4) R1.2 states there must be verification of coordination within 90 calendar days following "...identification or implementation..." of systems or changes. There is typically an enormous difference between the "identification" and the "implementation" of these systems. Would the SDT please clarify what is expected? (5) Sister Unit exemptions should be allowed for plants with multiple identical units that have identical equipment and control systems. (6) This Standard should only apply to generators with a nameplate rating of > 75 MVA and a connection to the interconnected transmission grid > 100 kV. (7) The use of "Stead state stability limit" in bullet #4 in R1 and the use of the phrase "...system steady state operating conditions." in R1.1.1, seem to conflict. Is the term in R1 intended to represent system conditions AFTER an N-1 contingency, or during N-0 conditions?
Group
SERC Generation sub-committee
Joe Spencer - SERC staff
Yes
Please clarify if real and reactive verification can be performed at different times.
No

The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data.
No
Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to be the same.
No
We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentially identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).
No
Although we agree that four points are sufficient to provide a straight line approximation over a unit's operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, The GS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Yes
Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Yes
But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit below (attempted to include graphic).
No GS comment
No
It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power

capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." The SERC GS could provide a template for this. Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their under excitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference comment 2 under Question 14 for additional discussion on the verification methods. Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate (see comments to question #10). It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5 year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and thus we also request that this requirement be revised to allow additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the

phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 11) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 12) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 13) It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations) .As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 14) This standard establishes a periodic generator testing regime which, when implemented on a large number of generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach to verify reactive capability for most generators. Targeted testing can then be used on a limited basis.
Group
ACES Power Members
Jason Marshall
Yes
No
The requirements appear to correctly show the data being submitted to the TP. However, Transmission Owner in 3.4 of Attachment 1 should be Transmission Planner.
Yes
Yes

No
Yes
Yes
Yes
No
It is not clear how this standard is applicable to variable static reactive resources located at asynchronous generating facilities. They do not appear in applicability section.
Yes
Yes
No
The data retention for M1 may not be consistent with NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. In that bulletin, NERC appears to require some level of evidence for the entire audit period.
Yes
In part 4.2.3 of the Applicability section, the phrase “regardless of size included in a Transmission Operator’s restoration plan” should be struck. It is redundant with definition of Blackstart Resource.
Individual
Rex Roehl
Indeck Energy Services
No
Testing will be more difficult if combined.
No
TP
No
No temperature adjustment can be done reliably with real and reactive power. Real power may be adjusted, but not with reactive. Generator can make the adjustment if there is a nationwide standard. If not, then regional standards will be required to specify the values.
No
Some standards need to apply to all registered generators. These do not. The minimum unit size should be at the NERC Reportable Disturbance level for the control area. Variations in any other sized unit need not even be reported. This isn't about treating all generators fairly, it is about what is affecting BPS reliability.
No
We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we

believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, we not believe that verification for leading capability should not be required where operational practices preclude operation in a leading mode. Finally, for units where verification of multiple points are needed to satisfy the FERC directive, we agree that 2 points are sufficient to verify the lagging capability and 2 points are sufficient to verify the leading capability across the generator MW operating range. However, trying to represent that with a straight line approximation between the two points could eliminate a large portion of the available capability curve around rated pf when rated MW for the unit falls within the stator rating segment of the capability curve, especially when it approaches the stator limit (which can occur for some units).
Yes
No
Only if they are required for particular units.
No
They are owned and registered differently.
No
No
Engineering analysis should also be available
No
The point is that the rating should be changed to the value tested. If a unit can't reach it, it's not a rating.
Yes
The temperature adjustment probably varies by region. There is no basis in the ROP for members on one region to vote on requirements for another region. There are nationwide standards or regional standards. The SDT can't have it both ways.
Yes
For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
Yes
Yes
Yes
The standard as drafted contains regional standards (ERCOT vs WECC). The ROP doesn't permit members of one region to vote on regional requirements for other regions. Regional standards will be required to implement regional differences.
Yes
Regional differences violate the ROP.

Yes
This standard imposes significant costs on generators and requires them to, in many cases unless they are also a transmission company, to hire consultants to conduct the verification. There is no evidence that unverified model data for units smaller than the level of the NERC Reportable Disturbance for the control area will have any impact on BPS reliability.
No
Not sync condensers
No
Not registered
No
There is no evidence that this needs to be done to any unit less than the NERC Reportable Disturbance level for the control area.
No
For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
No
One year history should be sufficient. It's about the verification, not keeping paper or electronic records forever.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
No
No
Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of the BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Yes
No
30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Yes
Yes
Yes
Yes

No
If by expected, it means maximum/minimum, then no. In many operating conditions, one does not get within 20% of the maximum/minimum. Need to be clear about what expected means.
No
No
Yes
The proposed VSL levels are spaced 10 days apart. For a test which is done once in a 5 year, it is unnecessarily restrictive. The minimum spacing between the VSLs should be 90 days. Reporting results 90 days late or even a 180 days late does not cause any concern for a planning horizon study. This data is only needed for such studies and such cases are typically updated annually. The real power verification tests are unnecessary and do not add any value. The peaking unit with less than 5% capacity factor should be expempt.
Yes
Yes
No
No
Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Yes
No
30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Yes
Yes
No
No
Verification on unites less than 50 MVA is unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Yes
No
30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Yes
Yes
Yes

Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
No
In the ERCOT Region, Oncor believes that the appropriate entity to receive this information is the Planning Authority.
Yes
Oncor believes that this information should be submitted to the Planning Authority in the ERCOT Region and that they (the Planning Authority) should coordinate with the Generator Owner in the development of any correction factor and the appropriate temperature value that should be used.
Yes
No
Unit reactive capability is limited by many factors and cannot be estimated using a straight line approach, a region of reactive capability over various power levels using actual operating limits is more realistic.
Yes
Yes
No
Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard
No
Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard therefore we believe this criterion is not applicable to this standard.
Yes
No
Any operational varation from expected should be explained by the Generator Owner and a solution to provide full capability be presented.
Yes
Oncor also recommends that consideration be given to a regional variance in that the information required of the Generator Owner as specified in R1 should be provided to the Planning Authority in the ERCOT region and not the Transmission Planner. This would align with current protocols, operating guide and planning guide as it relates to resource testing.
Yes
In the ERCOT Region, resource testing and most all communications regarding unit performance is facilitated by the Independent System Operator who is the Planning Authority. This is consistent with current, ERCOT protocols, operating guide and planning guide.
No
No
Yes
No

Oncor does not believe that the inclusion of dynamic reactive devices such as SVC's should be included in MOD-027-1
Yes
Oncor is in general agreement of the standards however, Oncor believes that the Transmission Planner in the ERCOT Region is not the appropriate receiving entity of test verification data from the Generator Owner. Oncor believes that a regional variance should be given strong consideration such that the Planning Authority would be the receiving entity of all testing data from the Generator Owner. This would align with current ERCOT protocols, operating guide and planning guide at it relates to resource testing and verification.
Yes
Sections 3.2.1 and 3.2.2 of the ERCOT Operating Guides direct resource entities to communicate operating capabilities directly to the ERCOT ISO. The ERCOT ISO is registered as the Planning Authority. Section 3.3 of the ERCOT Operating Guides direct resource entities to communicate changes to operating capabilities to the ERCOT ISO. Various resource test requirements as listed in Section 8 of the ERCOT Operating Guides indicate data submissions to the ERCOT ISO.
No
Yes
Yes
No
Oncor does not believe that there is a reliability need for including dynamic or static reactive resources (e.g. static VAr compensators) that are not located at generating sites in this standard.
Yes
Yes
Yes
Yes
Yes
No
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
IMPA supports combining MOD-024-1 and MOD-025-1 into a single standard MOD-025-2.
No
According to VAR-002-1, the Transmission Operator is responsible for providing the voltage schedule to the Generator Operator. This voltage schedule is to ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained. It seems like the TOP should know what the generating units are capable of producing when it comes to reactive power. IMPA recommends adding the TOP entity to the requirement 1.3.
No
The owner or operator of the generating unit should do the temperature correction to a specified temperature as directed. The owner will possess the curves and be better acquainted with the unit's limitation and temperature correction.

Yes
IMPA supports the SDT’s decision to have the standard be applicable to the compliance registry.
No
IMPA believes that four point testing is excessive and that only two points need to be verified. Those two points would be over-excitged (lagging) and under-excited (leading) reactive capability at the rated Real Power capability only. The two points verified at the expected minimum Real Power output is excessive. Reactive power support happens when load is high and generating units are running at maximum Real Output capability.
Yes
Yes
Yes
Yes
Yes
Yes
IMPA believes that the first sentence of requirement 2.1. does not read correctly in the sense that it is requiring the verification of Real Power Capability at maximum over-excited and under-excited reactive capability at rated gross Real Power Capability. This sentence would make sense if Real was removed at the beginning of the sentence and read “Perform verification of Reactive Power capability of all generating…”. Requirement 2.2 covers real power testing requirements. Since Real power needs to be removed from 2.1 then requirement 2.3 needs to have the requirement 2.2 added to it to cover the Real power testing time.
Yes
IMPA supports the application of the standard to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 50MVA and greater.
Yes
Yes
No
IMPA is answering this question in conjunction with question 9. IMPA believes that the study should happen initially and only if a change is made or equipment is modified. If using this approach, the previous evidence and the new evidence should be retained.

Yes
IMPA does not understand the need to perform the coordination type of study every five years. It should be performed initially and only if something changes that would require a new coordination study. IMPA could see the need to verify the settings on the voltage regulating equipment, etc. just as you would with relay testing but why go through a complete study every 5 years. IMPA recommends performing the coordination study initially as per the timetable listed in the effective dates (section 5) and then again prior to the implementation of systems, equipment, setting changes, etc. IMPA recommends not using the words “verify the existence” in requirement 1.2. This wording is very vague in the sense that it may require just a review of the document to ensure no changes or does it mean that another coordination study needs to be performed. IMPA recommends using the wording “shall review the coordination identified in Requirement R1 at least once every five years or perform the coordination identified in Requirement R1 within 90 calendar days… ” if this is the intent of the SDT.
Individual
Oscar Herrera
Los Angeles Department of Water and Power
LADWP does not have a position on this question at this time.
LADWP does not have a position on this question at this time.
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LADWP does not have a position on this question at this time.
Yes
MOD-025 Attachment 1 Sec. 2.1 During normal operations, it is typical to have many wind and solar units not working due to equipment malfunctions such as faults. How will failures that prevent the testing of 90% of equipment integrate with the standard? MOD-025 Attachment 1 Sec. 4 Will As-Built Project Drawings suffice for the requirement? The development of new one-line diagrams for a simplified version could have a significant impact because it will require the support of drafting resources which might not be available potentially delaying the submittals of Models and Data Reports. The requirement of directional arrows for Reactive Power Flows can be superimposed on the As-Built drawings. MOD-025 Attachment 1, Sec. 5 From a user’s perspective, it would be useful to get some language from the ERO that quantifies and qualifies what type of control system conditions would trigger the need for a new model and data verification, and also to have access to a comprehensive sample of a model and data verification test plan. This would allow the user to better manage its compliance implementation phase.
LADWP does not have a position on this question at this time.
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LADWP does not have a position on this question at this time.
LADWP does not have a position on this question at this time.
Individual
John Yale
Chelan County PUD
Yes
Yes
No
Should only be required if it impacts the data or test performed. For most generation it would not.
No
For multi-unit hydro and wind plants this can become a large effort. A "type" test where one of an identical family of units is verified is more practical and should provide sufficient data.
Yes
It is adequate, but variation from testing at the extremes should be permitted due to conditions - in some applications it is difficult to go to full buck or boost without absorbine/providing the reactive power from another unit without impacting the voltage schedule. Should testing cause the voltage schedule to be violated (or worse an unacceptable voltage condition), what should govern? It is unreasonable to expect that every plant over 75MVA can go to these conditions and hold them for an hour.
No
What is the basis for an hour? It should be tested to demonstrate stability at that point and not trip. After that why stay at an extreme condition? If you are concerned about MVA verification that can be done at any value, certainly design output and power factor is a better point.
Yes
Yes
For hydro, 20% of min and max reactive may be difficult to achieve. Salient pole machines have much greater lattitude than thermal, but system and bus conditions dictate if it is possible. Allowance should be made for realities in these cases. Again, what will dictate - voltage schedule or testing requirements?
Voltage schedule requirements may conflict.
No
Yes
Yes
No
No

No
Yes
Yes
Yes
If there is a reliabiity need for synch-condensors and generators, why not SVCs for similar minimum capacity? don't they similarly impact system reliability?
Yes
Yes
Yes
Yes
No
No

Consideration of Comments on Generator Verification (MOD-025-2) — Project 2007-09

The Generator Verification drafting team thanks all commenters who submitted comments on the first posting of MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability (Project 2007-09). This standard was posted for a 30-day public comment period from June 15, 2011 through July 15, 2011. The stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing nine of the 10 industry segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

SUMMARY CONSIDERATION:

A number of commenters suggested revisions for clarity that were accepted by the GVSDT. Minor changes were made to the standard to incorporate those suggestions.

- Language was added to recommend that the AVR be in automatic control while conducting reactive capability testing, but that reactive capability testing must be done even if the AVR is not available. The following language was also added to allow flexibility if 90 percent of the generation is not available when testing wind turbines or photovoltaic inverters:

  "If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold."

- When polled, most stakeholders agree with combining MOD-024-1 and MOD-025-1 into a single standard. Several commenters suggested that the standard be clarified to indicate that Real and Reactive Power testing may be performed under separate tests. The GVSDT agrees and has separated R1 into two requirements to allow for separate Real and Reactive Power testing. The intent of these requirements remains unchanged. R1 now deals with Real Power testing only while R2 deals with Reactive Power testing. The measure and VSL for R1 were also revised to match the requirements.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf.

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

- A statement was also added to the beginning of Attachment 1 for additional clarity:

  "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."

- There was an error in the question relating to the Transmission Owner on the previous comment form. The question should have asked if the Transmission Planner was the appropriate entity rather than the Transmission Owner. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. The GVSDT will confirm this with an additional question on this topic in the next posting.

- With regard to correction factors for verifications, many commenters pointed out there are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The GVSDT has revised the standard to include any parameter that the Generator Owner determines is required to make the ambient correction in Attachment 1:

  3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

  - Ambient air temperature
  - Relative humidity
  - Cooling water temperature

  The standard gives the Transmission Planner the discretion to request ambient condition correction at time of verification.

- There was overwhelming stakeholder support for verifying synchronous condensers as a reactive resource under MOD-025-2. Some stakeholders suggested that consideration be given under this or a different standard for verification of other reactive resources.

  The SDT added the following sentence to Attachment 1 in response to a stakeholder comment for clarity:

  "If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."

- There was an error in the comment form for the question regarding Synchronous Condenser size. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. While some commenters suggested values higher than 20 MVA, technical justification was not provided for a value exceeding the generator registration criterion of 20 MVA. The GVSDT will confirm this with an additional question on this topic in the next posting.

Commenters have identified regional variances currently in effect as required by MOD-024 and MOD-025. It is anticipated that these regional standards will be retired once MOD-025-2 is approved. Language provided by Reliability*First* staff has been added to the Implementation plan concerning the Reliability*First* standards:

> "It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements."

Index to Questions, Comments, and Responses

1. The SDT has proposed that the requirements of MOD-024-1 and MOD-025-1 be combined into a single standard MOD-025-2. Do you agree with this approach? If not, please explain. 17
2. The SDT has proposed that the data from MOD-025-2 be submitted to the Transmission Owner. Do you believe the Transmission Owner is the appropriate entity to receive this data? If not, please explain. 26
3. The SDT has proposed that the ambient temperature during the verification be provided to the Transmission Owner as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature if needed. Do you feel the standard should require that the Real Power data submitted be temperature adjusted to some other than ambient temperature? If yes, please explain and include which entity you think should perform the correction and which entity should determine the temperature value that should be used for the correction.43
4. The SDT believes that verification should be performed on units that are connected down to 100 kV. The SDT has also provided how verification should be handled in plants/facilities that are greater than 75 MVA in aggregate gross nameplate rating. The Standard requires a separate verification for every unit greater than 20 MVA gross nameplate rating. This is consistent with the current Compliance Registry. Units 20 MVA and smaller, in a plant/Facility greater than 75 MVA, can be verified separately or in aggregate as the Generator Owner chooses. Do you agree with the SDT's decision to have the Standard be applicable to the compliance registry? If not, please explain. ... 61
5. The draft standard requires that the Reactive Power capability be verified at four points: over-excited (lagging) and under-excited (leading) reactive capability at (1) the rated Real Power capability and (2) expected minimum Real Power output. The SDT believes that this is consistent with the FERC directive in Order 693 at P1321, "Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range." Do you agree that the four points proposed by the SDT is adequate to provide a straight line approximation to a unit's Reactive Power capability over its actual operating range? If not, please explain. 74
6. Verification of over-excited reactive capability at rated Real Power Capability is required to be conducted over a minimum of one hour. Do you agree with the verification time? If not, please explain. 89
7. Verification of (1) under-excited reactive capability at rated Real Power of the most recent gross verified Real Power capability reported, (2) under-excited reactive capability at expected minimum Real Power output and (3) over-excited reactive capability at expected minimum Real Power output, are all to be recorded as soon as a limit is encountered. Do you agree that such data recorded as soon as a limit is encountered is appropriate for such verification? If not, please explain.................... 98
8. Synchronous condensers are also reactive resources that may be important to reliability, but they are not generators. The SDT proposes that synchronous condensers be verified under MOD-025-2. Do you feel that this is appropriate?....................... 109
9. The SDT proposes that the size of synchronous condensers to be verified be limited to those greater than 50 MVA. Do you feel that this size criterion for synchronous condenser verification is appropriate? 115

10. Either operational data or staged testing is allowed by the standard for verification. Do you agree that these two methods of verification are acceptable? If not, please explain. 122

11. If operational data is utilized, the standard requires the verification be within 20% of the expected value. Do you agree with the 20% requirement? If not, please explain. 131

12. Are you aware of any regional variances that would be required for this standard? .. 149

13. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? ... 155

14. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please provide a reference to the section, requirement or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal. 161

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-Serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council , LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Marcela Caballero	IID	WECC	5
5.	Cathy Bretz	IID	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Albert DiCaprio	IRC Standards Review Committee (joint comments)		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Patrick Brown	PJM	RFC	2
3.	Ben Li	IESO	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	David Thorne	Pepco Holdings Inc Affiliates	X		X							
6.	Group	Jonathan Sykes, Chair	NERC System Protection and Control Subcommittee	X			X	X					X
7.	Group	Carol Gerou	Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
4.	Mark Thompson	AESO	WECC	2
5.	Steve Myers	ERCOT	ERCOT	2

Group 5 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3
2.	Alivan Depew	Pepco Holdings Inc	RFC	1, 3

Group 6: No additional members listed.

Group 7 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Power Dist	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Copperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
10.	Joseph DePoorter	Madison Gas and Electric Company	MRO	3, 4, 5, 6
11.	Scott Nichols	Rochester Public Utilities	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
13.	Richard Burt	Minnkota Power Cooperative	MRO	1, 3, 5, 6
14.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
15.	Scott Bos	Muscatine Power and Water	MRO	3, 4, 5, 6
16.	Lee Kittleson	Otter Tail Power Company	MRO	5, 1, 3, 6
17.	Marie Knox	Midwest ISO	MRO	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jonathan Hayes	SPP Reliability Standards Development Team										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Reynolds	Sunflower Electric Power Corporation	SPP	1
2.	Valerie Pinamonti	AEP	SPP	1, 3, 5
3.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
5.	Louis Guidry	CLECO	SPP	1, 3, 5
6.	Sean Simpson	McPhearson Board of Public Utilities	SPP	1, 3, 5
7.	Robert Rhodes	SPP	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Co.	SERC	1
2.	James Manning	NC Electric Membership Corp.	SERC	1
3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1
4.	Pat Huntley	SERC Reliability Corp.	SERC	10
5.	Bob Jones	Southern Company Services	SERC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Tim Brown	Idaho Power-Power Production					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Guy Colpron	Idaho Power	WECC	5
2.	Mark Pfeifer	Idaho Power	WECC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Phil Pierce	Santee Cooper	SERC	5
3.	Paul Camilletti	Santee Cooper	SERC	5
4.	Rene Free	Santee Cooper		1
5.	Tom Curtis	Santee Cooper	SERC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Annette Bannon	PPL Generation					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Leland McMillan	PPL Montana, LLC	WECC	5
2.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
3.		PPL Brunner Island, LLC	RFC	5
4.		PPL Holtwood, LLC	RFC	5
5.		PPL Martins Creek, LLC	RFC	5
6.		PPL Montour, LLC	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		MRO	5, 6
2.	Connie Lowe		SERC	5, 6
3.	Michael Gildea		RFC	5, 6
4.	Larry Whanger		SERC	5
5.	Mike Crowley		SERC	1, 3
6.	Jeff Bailey		MRO	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Baznik	FE	RFC	1
2.	Bill Duge	FE	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3. Brian Orians		FE	RFC 5										
15.	Group	Joe Spencer - SERC Bob Jones - DRS chair	SERC Dynamics Review Sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

				1	2	3	4	5	6	7	8	9	10
16.	Group	Mallory Huggins	NERC Staff										

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
17.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Brown	PSE&G	RFC	1, 3
2.	Clint Bogan	PSEG Fossil	RFC	5
3.	Peter Dolan	PSEG ER&T	RFC	6
4.	Scott Slickers	PSEG Fossil	NPCC	5

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Eric Schmidt	PSEG ER&T	NPCC	6
6.	Mikhail Falkovich	PSEG Fossil	ERCOT	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Joe Spencer - SERC staff	SERC Generation sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Jason Marshall	ACES Power Members						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Jones	AEPCO/SWTC	WECC	1, 3, 5
2.	Mohan Sachdeva	Buckeye Power	RFC	4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Bo Jones	Westar Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Antonio Grayson	Southern Company					X					
23.	Individual	David Thompson	Tennessee Valley Authority GO					X					
24.	Individual	David Youngblood	Luminant Power					X					
25.	Individual	David Miller	Lakeland Electric	X									
26.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
29.	Individual	Edward Cambridge	APS	X		X		X					
30.	Individual	Brad Haralson	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
32.	Individual	Greg Campoli	New York Independent System Operator		X								
33.	Individual	Samuel Reed	Tri-State Generation and Transmission, In.	X				X					
34.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
36.	Individual	Mace Hunter	Lakeland Electric	X		X		X					
37.	Individual	John Bee	Exelon	X		X		X					
38.	Individual	Michael Goggin	American Wind Energy Association								X		
39.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
40.	Individual	Bob Casey	Georgia Transmission Corporation	X									
41.	Individual	Jeanie Doty	Austin Energy					X					
42.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
43.	Individual	Michael Brytowski	Great River Energy	X		X		X					
44.	Individual	Vladimir Stanisic	BC Hydro	X	X	X		X					
45.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
46.	Individual	Amir Hammad	Constellation Power Generation					X					
47.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
48.	Individual	Thad Ness	American Electric Power	X		X		X	X				
49.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
50.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					
51.	Individual	Gary Chmiel	GE Energy										
52.	Individual	Kathleen Goodman	ISO New England		X								
53.	Individual	Dan Hansen	GenOn Energy					X					
54.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
55.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
56.	Individual	Eric Ruskamp	Lincoln Electric System	X		X		X	X				
57.	Individual	Jose H Escamilla	CPS Energy			X							
58.	Individual	Michael Falvo	Independent Electricity System Operator		X								
59.	Individual	Karen Alford	Gainesville Regional Utilities	X		X		X					
60.	Individual	Kirit Shah	Ameren	X		X		X	X				
61.	Individual	Rex Roehl	Indeck Energy Services					X					
62.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
63.	Individual	Scott Berry	Indiana Municipal Power Agency				X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
64.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
65.	Individual	John Yale	Chelan County PUD	X				X	X				

1. The SDT has proposed that the requirements of MOD-024-1 and MOD-025-1 be combined into a single standard MOD-025-2. Do you agree with this approach? If not, please explain.

Summary Consideration: Most stakeholders agree with combining MOD-024-1 and MOD-025-1 into a single standard. Several commenters suggested that the standard be clarified to indicate that Real and Reactive testing may be performed under separate tests. The GVSDT agrees and separated R1 into two requirements to allow for separate Real and Reactive testing. The intent of these requirements remains unchanged. R1 now deals with Real Power testing only, while R2 deals with Reactive Power testing. The measure and VSL for R1 were also revised to match the requirements.

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

A statement was also added to the beginning of Attachment 1:

"It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below. If an applicable Facility is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>IRC Standards Review Committee (joint comments)</td><td>No</td><td>It is not a matter of whether the requirements for real power verification is in one numbered standard and reactive verification is in another numbered standard, the important point is that the requirements be clear and separate. The posted standard fails that test by combining two requirements into one. It may look cleaner writing the two together; the problem is with the fact that such a format has the potential to needlessly risk getting some data when the other data is NOT available. If an asset owner could provide real data but not reactive data, the standard as written would incent the owner from providing either data (why waste a test when the owner knows it will be non-compliant anyway? By separating the two actions, the owner would be compliant with one and non-compliant with the other requirement - but the planner would have at least half the information.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for real and reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."</td></tr>
<tr><td>PPL Generation</td><td>No</td><td>MOD-024 has already been incorporated into a regional standard by RFC (MOD-024-RFC); and, as is implicit in the term "standard," these documents should change only infrequently.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT is coordinating with RFC regarding the regional standard. The following statement was provided by RFC and will be added to the implementation plan for MOD-025-2.

"It is the intent of ReliabilityFirst to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the ReliabilityFirst Reliability Standards Development Procedure will be followed for any such revisions or retirements."</td></tr>
<tr><td>Associated Electric Cooperative, Inc.</td><td>No</td><td>Real power verification is typically done using historical operating data because units commonly operate at full real power capability. Reactive power verification will most likely not be done using historical operating data. This standard implies that these verifications will be done at the same time. Applicable standards should allow for real and reactive verifications at different times.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard."</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Exelon</td><td>No</td><td>The requirements of MOD-024-1 and MOD-025-1 should remain separate. The testing periodicities and the reporting requirements for both of the existing Standards are different. In addition, the SDT needs to closely coordinate with existing testing and reporting requirements 1) Regional requirements and reporting criteria (e.g., MOD-024-RFC-01.1) and 2) Transmission Planner requirements (e.g., PJM has separate reporting criteria).If the SDT continues to push for a combined Standard, then consideration must be given to splitting out the requirements (i.e., separate Attachments) for Real and Reactive Testing.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment.

1) The GVSDT is coordinating with RFC regarding the regional standard. The following statement was provided by RFC and will be added to the Implementation plan for MOD-025-2.

“It is the intent of ReliabilityFirst to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review is to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the ReliabilityFirst Reliability Standards Development Procedure will be followed for any such revisions or retirements.”

2) Requirements other than NERC or regional standards are outside the scope of the GVSDT. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, ”It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”</td></tr>
<tr><td>Wisconsin Electric</td><td>No</td><td>The testing of reactive power capability has inherent risks due to the need for coordination with relaying and excitation limiters, and requires more technical resources than real power testing. Therefore the verification of real and reactive power would best be addressed in separate standards.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. We believe that this change will address your concern. A statement was also added to the beginning of Attachment 1 stating, “It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”</td></tr>
<tr><td>Indeck Energy Services</td><td>No</td><td>Testing will be more difficult if combined.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, ”It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
FirstEnergy	Yes	We agree that a “one-stop-shop” approach is appropriate for Real and Reactive Generator Verification requirements.
Response: The GVSDT thanks you for your comment.		
SERC Dynamics Review Sub-committee	Yes	Consolidating standards is beneficial
Response: The GVSDT thanks you for your comment.		
SERC Generation sub-committee	Yes	Please clarify if real and reactive verification can be performed at different times.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. The tests can be performed separately. A statement was also added to the beginning of Attachment 1 stating, “It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”		
Cowlitz County PUD	Yes	Combination of closely related standards simplifies compliance program development, and is welcome.
Response: The GVSDT thanks you for your comment.		
American Electric Power	Yes	In general, AEP is not opposed to combining MOD-024-1 and MOD-025-1 into a single MOD-025-2 standard.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that generator reactive testing necessarily requires validation at the real power extremes. This means there is no benefit to require separate testing.
Response: The GVSDT thanks you for your comment.		
Duke Energy	Yes	Yes, however need to define "Rated Real Power" so that entities are using a consistent basis for data reporting. MW validation is intrinsically connected to governor response issues and thus should be instead be combined with MOD-27 frequency response efforts and the following modeling parameters defined and

Organization	Yes or No	Question 1 Comment
		addressed:- Pmax o The continuous operating limit o The ultimate max emergency output. o Should there consider weather conditions (summer or winter, etc.). o PMAX associated with Transient stability - is it the same as for LF o Is this on the order of 105% or 110% or ??% of normal max loading. Please clarify if real and reactive verification can be performed at different times.
Response: The GVSDT thanks you for your comment. To address your concern, Step 2.1 of Attachment 1 was modified by adding the phrase "(not emergency)" to the first sentence; which states, "The generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." **The tests can be performed separately.**		
Lincoln Electric System	Yes	Yes, but the verification periods should be different for Real and Reactive Power. It is not unreasonable to expect a Real Power verification test on an annual basis, as this data is usually available annually at some time when the unit is operated to serve load. It states the purpose of the Project 2007-09 Generator Verification is: "To ensure that generator models accurately reflect the generator's capabilities and operating characteristics." Without annual operation to verify Real Power it appears difficult to ensure this objective with a high degree of confidence.
Response: The GVSDT thanks you for your comment. The GVSDT has separated R1 into two separate requirements for Real and Reactive testing. A statement was also added to the beginning of Attachment 1 stating, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard." **Regarding periodicity, the verification data is being utilized for the planning time horizon; and as such, the GVSDT believes that there is little, if any, reliability benefit associated with performing more frequent Real Power verification.**		
Independent Electricity System Operator	Yes	We support this approach. The real and reactive power capabilities are related and hence having them addressed in one standard would enhance verification efficiency.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 1 Comment
Indiana Municipal Power Agency	Yes	IMPA supports combining MOD-024-1 and MOD-025-1 into a single standard MOD-025-2.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
Pepco Holdings Inc Affiliates	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee	Yes	
Idaho Power-Power Production	Yes	Yes
Santee Cooper	Yes	
Dominion	Yes	
NERC Staff	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	

Organization	Yes or No	Question 1 Comment
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Dynegy Inc.	Yes	
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Lakeland Electric	Yes	
American Wind Energy	Yes	

Organization	Yes or No	Question 1 Comment
Association		
Tacoma Power	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Great River Energy	Yes	
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Wisconsin Public Service Corp	Yes	
GE Energy	Yes	
ISO New England	Yes	
GenOn Energy	Yes	
Manitoba Hydro	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Oncor Electric Delivery Company LLC	Yes	
Chelan County PUD	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

2. The SDT has proposed that the data from MOD-025-2 be submitted to the Transmission Owner. Do you believe the Transmission Owner is the appropriate entity to receive this data? If not, please explain.

Summary Consideration: There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. A few commenters suggested that the information should be provided to other reliability entities, such as the Reliability Coordinator. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the planning and Real-time time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

    c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

The GVSDT has not revised the requirement with respect to submitting the data to the Transmission Planner. The requirement continues to require the data be submitted to the Transmission Planner.

Organization	Yes or No	Question 2 Comment
LG&E and KU Energy	No	Either the Planning Authority of the Transmission Planner are the more likely entity to submit data rather than the Transmission Owner as indicted in R2.3
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. You are correct that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1.		
Northeast Power Coordinating	No	The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the

Organization	Yes or No	Question 2 Comment
Council		data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator or Transmission Operator. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities: **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
IRC Standards Review Committee (joint comments)	No	MOD-025 is a requirement on owners to verify data, nowhere does the requirement state who the data goes to. Of course the owner is NOT the appropriate entity to send the data to since they are the ones that are responsible for generating the information. This standard has many issues related to who gets what data and why. There is no requirement to have the data in the first place. The standard would be better to require a planning entity to request the data that that entity needs to do its mandated functions. Once the planner asks for the data, then the owner can provide / verify the information being asked for. The SDT has rejected the comments that other standards already provide this information. The SDT has parsed the terms "capability" and "rating". However, the NERC Glossary defines Rating as strictly a transmission line term, and the word capability is not defined. Capability does show up within other

Organization	Yes or No	Question 2 Comment
		definitions related to Transfers and other transmission terms. The SDT is asked to review their findings in light of the above, and in light of the FAC and TOP standards purposes. The TOP standard has developed the flexible approach of having an entity ask for the data it needs, and for the receiver of the request to provide the needed information. This approach eliminates the idea of a common requirement for all planners (whether or not they want the data elements in the posted Attachment 2).Our proposal is to have a requirement (if it does not already exist) mandating entities asks for what they want, and a separate requirement for the receivers to provide just that data. If the revised standard is written in that fashion than the new MOD-025 COULD replace the old MOD-024 because there would be no need to specify reactive data from real data, because the entities who are asking for the data will do that for you. Editorial :(1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”, we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.”, or be revised to: “To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 2 Comment
(First paragraph) The GVSDT points out that Requirement R1, Parts 1.3 and 2.3 both specify that the responsible entity shall, "Submit within 90 calendar days of the date the data is recorded to its Transmission Planner." **(Second Paragraph) The GVSDT has revised the MOD-024-1 and MOD-025-1 planning standards. Early in the project, the GVSDT considered the approach suggested of having entities requiring the verified data to also specify the data that they require. This approach was universally opposed by the members of the GVSDT who work in Transmission Planning because (1) it is common knowledge that Real and Reactive Power data is required, and (2) any communication requesting data from the generating entity will need to be documented and verified; which is a burdensome task without reliability benefit.** **(Editorial 1) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:** **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.** **The GVSDT believes that the Transmission Planner is the appropriate entity.** **(Editorial 2) The purpose statement has been revised to:** **1.** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BES (BES) reliability.		
Independent Electricity System Operator	No	(1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: "To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability", we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership

Organization	Yes or No	Question 2 Comment
		and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.”, or be revised to: “To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”.

Response: The GVSDT thanks you for your comment. Please see responses above.

(Section 1) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource

Organization	Yes or No	Question 2 Comment
Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers. **The GVSDT believes that the Transmission Planner is the appropriate entity.** **(Section 2) The purpose statement has been revised to:** **1.** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BESreliability. .		
Pepco Holdings Inc Affiliates	No	The standard in Sec B-R1.3 and R2.3 state to submit the data to the TP not the TO. The TP is the appropriate entity. However, the TOP and the TOP also have need of the data. Should dissemination to these entities be covered in the requirements also?
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons.		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	The standard states that the data be submitted to the Transmission Planner and we agree with that approach.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
SPP Reliability Standards Development Team	No	Is there a typo in the question? Should Transmission Owner be Transmission Planner? If not then adding the Transmission Owner as an intermediate step before submitting data to the Transmission Planner isn't needed.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		

Organization	Yes or No	Question 2 Comment
SERC Planning Standards Subcommittee	No	The PSS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
PPL Generation	No	PPL Generation, LLC's Registered Entities are already performing VAR testing and reporting the results to our RTO (PJM), in accordance with Manual PJM-14D, and PJM then makes this information available to other entities. It would be very confusing to have to conduct two different VAR tests (PJM and NERC), possibly resulting in two different values (depending on the final wording of MOD-025), reported to two different entities.
Response: The GVSDT thanks you for your comment. The GVSDT is not aware of the testing required by PJM. If the testing requirements are the same, then a single test could be performed and reported to satisfy both PJM and NERC requirements.		
Dominion	No	R1.3 and R2.3 require submittal to Transmission Planner, not Transmission Owner. We believe it is also appropriate to submit these results to the Resource Planner as we are unaware of an existing reliability standard that requires this information be provided to that entity (even though aware that version 5 of the Functional Model (on page 28) states the Resource Planner "Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans."Further, we believe it is also appropriate to submit these results to the Balancing Authority and Transmission Operator despite the fact that they may request verification pursuant to TOP-002a @R13. We believe that, given the owner is being required to verify real and reactive capability, and report the results to one entity, requiring reporting to additional entities who could find the information useful in its reliability assessment (whether in the planning or operating time horizon) adds significant value at little additional effort.
Response: The GVSDT thanks you for your comment. **(First part) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.** **(Second part)** As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by		

Organization	Yes or No	Question 2 Comment
other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons.		
FirstEnergy	No	The standard in Subpart 1.3 says that the Transmission Planner is the entity that shall receive this information. We agree that it should be the TP. Also, we question whether or not the Planning Coordinator should also receive this information. Furthermore, with respect to how this information will be used by the planning entities, the team needs to assure that there is no duplication of efforts with MOD-010-0 and MOD-011-0. We suggest that MOD-010-0 and MOD-011-0 get revised to remove redundancies, or make it clear that the entity may supply existing MOD-010/-011 compliance evidence to show compliance with MOD-025-2.
Response: The GVSDT thanks you for your comment. Please see responses above. **(First part) There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.** **(Second part) MOD-010-0 and MOD-011-0 pertain to data and equipment characteristics, not validation requirements; therefore, the standards do not duplicate requirements.**		
SERC Dynamics Review Sub-committee	No	The DRS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
NERC Staff	No	Requirement R1, part 1.3 and Requirement R2, part 2.3 indicate that data is to be submitted to the Transmission Planner. We agree that the data should be submitted to the Transmission Planner, not the Transmission Owner. Further, we believe that the data should be provided to all entities that have need of the data, including the Transmission Operators and Reliability Coordinators who need the data for their operational planning and real-time models.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner		

Organization	Yes or No	Question 2 Comment
has the following relationships with other entities: 2. Collects information including: c. Generator unit performance characteristics and capabilities from Generator Owners. 5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners. 6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers. The GVSDT believes that the Transmission Planner is the appropriate entity.		
Public Service Enterprise Group	No	MOD-025-2 requires that data be submitted by GOs or TOs to their respective Transmission Planner (R2.3). It should not require that it be submitted to the Transmission Owner as the TO has no need for this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
SERC Generation sub-committee	No	The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
ACES Power Members	No	The requirements appear to correctly show the data being submitted to the TP. However, Transmission Owner in 3.4 of Attachment 1 should be Transmission Planner.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Attachment 1, Step 3.4 was revised to change responsibility from the Transmission Owner to the Generator Owner. This adjustment is made before the data is sent to the Transmission Planner.		
South Carolina Electric and Gas	No	SCE&G believes that the Transmission Planner (TP) should receive this information, consistent with the current version of the standard.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Associated Electric Cooperative, Inc.	No	The TP or PA seems more appropriate.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
New York Independent System Operator	No	In section B, R1.3, results are required to be submitted to the Transmission Planner. The NYISO agrees with R1.3.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Westar Energy	No	We agree data should be submitted to the Transmission Planner as written in the draft of the standard.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Southern Company	No	The TP or the PC is the entity who needs the data, not the TO. R1.3 and R2.3 specifies that the TP be given this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Tennessee Valley Authority GO	No	The TP or the PC (PA) is the entity who will use the data. R1.3 and R2.3 specifies that the TP be given this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Luminant Power	No	This is not applicable in the ERCOT region. Data should be submitted to TOP and BA. They are currently responsible to utilizing the information for grid reliability.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. MOD-025-2 is a long-term planning standard. The TOP and BA entities do not perform long-term planning functions.		
Cowlitz County PUD	No	Not all Transmission Owners have a complete system view of the BES, let alone modeling software. The standard as written specifies the Transmission Planner, and so the question appears to be in error. Following the purpose statement of the standard, the Planning Coordinator (formerly Planning Authority) might also need the data along with the Transmission Planner. To further complicate the matter, in WECC CUG meetings it has been brought up that entities are experiencing difficulty in identifying their Planning Coordinator and Transmission Planner. Such entities have been rebuffed when approaching the obvious candidates. Therefore, Cowlitz suggests that a mechanism must be devised such that Generator Owners will not left in a compliance quandary in their endeavors to identify the appropriate planner(s).
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities: **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.** **The GVSDT believes that the Transmission Planner is the appropriate entity. The GVSDT suggest contacting your regional Entity for help identifying your Planning Coordinator and Transmission Planner.**		
Exelon	No	The Transmission Planner should be the appropriate entity to receive this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Georgia Transmission	No	This question seems to have identified the TO in error. MOD025-2 requires data to be submitted to the TP.

Organization	Yes or No	Question 2 Comment
Corporation		TP is the appropriate entity to receive the data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Austin Energy	No	We believe question #2 may contain a typo. The Proposed Standard Requirement 1.3 correctly requires data submittal to the Transmission PLANNER (in our case ERCOT). The data should be submitted to the Transmission Planner as currently written in the Proposed Standard, not the Transmission Owner as stated in the comment questionnaire.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
BC Hydro	No	Not clear why data would be submitted to TO. Based on Functional Model, TP, TOP or PC would be more applicable.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Northeast Utilities	No	The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. **The standard applies to units greater than 20 MVA directly connected to the bulk power system.**		
Consolidated Edison Co. of NY, Inc.	No	The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is

Organization	Yes or No	Question 2 Comment
		responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. The standard applies to units greater than 20 MVA directly connected to the bulk power system.		
Ingleside Cogeneration LP	No	Cogeneration LP believes that the proper recipient is the Transmission Planner. The Transmission Planner in turn must supply the information to the Planning Authority, Reliability Coordinator, and/or Transmission Operator as needed. There is no apparent reason why the Transmission Owner should be in the loop. Attachment 1, Item 3.4 seems to be the only place in MOD-025-2 that the Transmission Owner is shown as the recipient of generator verification data. It should be changed to Transmission Planner - consistent with the rest of the standard.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
ISO New England	No	The data from MOD-25-2 should be submitted to the Transmission Operator. The Transmission Owner does not appear to be the correct functional entity. The Transmission Owner may not have the area view required for this testing. Real and Reactive Power Testing must be coordinated with the Transmission Operator to ensure that the system remains within all operating limits.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. MOD-025-2 is a long-term planning standard.		
Duke Energy	No	The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data. Both the TPs and Transmissions Operations entities need to have accurate model information and the Operating studies are much more critical for BES reliability.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">have asked if the Transmission Planner was the appropriate entity.</td></tr>
<tr><td>CPS Energy</td><td>No</td><td>The Transmission Planner is the appropriate entity to use the data.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.</td></tr>
<tr><td>Ameren</td><td>No</td><td>Both the Transmission Owner and Transmission Planner should receive it.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Per the NERC Reliability Functional Model (V5, Page 24), the Transmission Planner has the following relationships with other entities:
2. Collects information including:
c. Generator unit performance characteristics and capabilities from Generator Owners.
5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.
6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.
The GVSDT believes that the Transmission Planner is the appropriate entity.</td></tr>
<tr><td>Indeck Energy Services</td><td>No</td><td>TP</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.</td></tr>
<tr><td>Oncor Electric Delivery Company LLC</td><td>No</td><td>In the ERCOT Region, Oncor believes that the appropriate entity to receive this information is the Planning Authority.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
the following relationships with other entities: **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.** **The GVSDT believes that the Transmission Planner is the appropriate entity.**		
Indiana Municipal Power Agency	No	According to VAR-002-1, the Transmission Operator is responsible for providing the voltage schedule to the Generator Operator. This voltage schedule is to ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained. It seems like the TOP should know what the generating units are capable of producing when it comes to reactive power. IMPA recommends adding the TOP entity to the requirement 1.3.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. MOD-025-2 is a long-term planning standard. It is inappropriate to include operating entities as applicable entities under MOD-025-2.		
Lakeland Electric	Yes	A Transmission Owner may need to size conductors according to Generator output.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity. Your concern is addressed by the Interconnection agreements between TOs and GOs.		
Tri-State Generation and Transmission, In.	Yes	The standard also calls for the data to be submitted to the Transmission Planner, so this question seems ambiguous.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
American Electric Power	Yes	Draft Standard MOD-025-2 provisions 1.3 and 2.3 both state that the data be provided to the Transmission Planner, rather than the Transmission Owner as stated within this question #2. We agree that the

Organization	Yes or No	Question 2 Comment
		Transmission Planner is the correct recipient for this data.
Response: The GVSDT thanks you for your comment. There was an error in the question relating to the Transmission Owner. The question should have asked if the Transmission Planner was the appropriate entity.		
Arizona Public Service Company	Yes	
Imperial Irrigation District (IID)	Yes	
Idaho Power-Power Production		Yes
Santee Cooper	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
Xcel Energy	Yes	
Lakeland Electric	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
Dynegy Inc.	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	
Wisconsin Public Service Corp	Yes	

Organization	Yes or No	Question 2 Comment
Constellation Power Generation	Yes	
GenOn Energy	Yes	
Gainesville Regional Utilities	Yes	
Manitoba Hydro	Yes	
Chelan County PUD	Yes	
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

3. The SDT has proposed that the ambient temperature during the verification be provided to the Transmission Owner, as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature, if needed. Do you feel the standard should require that the Real Power data submitted be temperature-adjusted to some other-than-ambient temperature? If yes, please explain and include which entity you think should perform the correction and which entity should determine the temperature value that should be used for the correction.

Summary Consideration: Many commenters pointed out there are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner, rather than the Transmission Owner. The GVSDT has revised the standard to include any parameter that the GO determines is required to make ambient correction in Attachment 1:

3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature

The standard gives the Transmission Planner the discretion to request ambient condition correction at time of verification.

Organization	Yes or No	Question 3 Comment
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs. (1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator’s real power capability to reflect a difference in ambient temperature. If anyone, it should be the

Organization	Yes or No	Question 3 Comment
		Generator Owner. (2) Reporting the ambient temperature is unnecessary since it is only one of the many factors that could affect the real power output of a generator. Adjusting the real power capability for a different ambient temperature does not really provide a more accurate value, and can be misleading. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome, and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.
Response: The GVSDT thanks you for your comment. Early in the project, the GVSDT considered the approach suggested of having entities requiring the verified data to also specify the data that they require. This approach was universally opposed by the members of the GVSDT who work in Transmission Planning because (1) it is common knowledge that Real and Reactive Power data is required, and (2) any communication requesting data from the generating entity will need to be documented and verified; which is a burdensome task without reliability benefit. **The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments, if applicable, to the Generator Owner in support of your suggestion.** **There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies.**		
Independent Electricity System Operator	No	(1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator's real power capability to reflect a difference in ambient temperature. If anyone, it should be the Generator Owner. (2) There seems to be little value in reporting the ambient temperature for the purpose of making adjustments to measured Real Power capability since it is only one of the several factors that could affect the real power output of a generator. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome, and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner in support of your suggestion. **The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies. The GVSDT believes that Transmission Planners have sufficient expertise to properly apply temperature correction factor information provided by the GO. All data needed for adjusting MW capability is now required in Attachment 2 per FERC Order 693, Paragraph 1310.** **The GVSDT does not intend for entities to perform multiple tests. Instead, the GO simply provides a temperature correction factor with test data collected. As a matter of practicality, temperature correction factor information should already be captured as part of the internal process used for performing Real Power testing.** **Temperature correction is only intended to be applied during engineering analysis of collected data. Additional testing is not required or necessary.**		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	We recommend that in Item 3.4 of Attachment 1 the wording be changed from "to allow the Transmission Owner" to "to allow the Transmission Planner". We support the position that the ambient temperature at the end of the verification period and the correction factor should be provided to the Transmission Planner so that the Transmission Planner can adjust the verification results to the ambient temperature that is appropriate for its system planning assessments.
Response: The GVSDT thanks you for your comment. Item 3.4 in Attachment 1 provides guidance with respect to correction factors and has been revised to assign responsibility for making a temperature correction, if applicable, to the Generator Owner rather than the Transmission Owner: **3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** **• Ambient air temperature** **• Relative humidity** **• Cooling water temperature**		
PPL Generation	No	The correction of real power capability to other-than-tested ambient conditions, as is currently performed by PPL Generation Registered Entities for MOD-024-RFC, is a complex matter involving the wet-bulb temperature, condenser cleanliness and other factors beyond simply the dry-bulb temperature, especially when using a total-unit thermodynamic computer model for this purpose. One must also consider low-

Organization	Yes or No	Question 3 Comment
		ambient limitations; wintertime predicted capabilities must be truncated if they would otherwise exceed the generator or GSU rating. Corrections to other-than-tested ambients should be performed by the GO, using an on-request basis.
Response: The GVSDT thanks you for your comment. Early in the project, the GVSDT considered the approach suggested of having entities requiring the verified data to also specify the data that they require. This approach was universally opposed by the members of the GVSDT who work in Transmission Planning because (1) it is common knowledge that Real and Reactive Power data is required, and (2) any communication requesting data from the generating entity will need to be documented and verified; which is a burdensome task without reliability benefit. **There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies.** **The GO can include any or all of the factors mentioned in the comment when providing data correction factor information. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments, if requested, to the Generator Owner in support of your suggestion.**		
Idaho Power-Power Production	No	No
LG&E and KU Energy		GO's typically correct to back pressure. Any other adjustments should be performed by Transmission Operator
Response: The GVSDT thanks you for your comment. There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies. Since the GO will not know the temperature as specified by the Planner for a particular scenario, the GVSDT believes the best solution for this concern is to have the GO record the ambient temperature at time of verification and also provide correction factor information so the Planner can extrapolate data to a different temperature basis when performing studies. The SDT modified the standard to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner, rather than the Transmission Owner.		
FirstEnergy	No	We believe that it is the responsibility of the Generator Owner to have an appropriate Ambient Adjustment Methodology and make the necessary corrections to the data per its methodology before submitting it to the Transmission Owner. We suggest similar requirement regarding ambient adjustments as found in regional standards MOD-024-RFC-01 and MOD-025-RFC-01.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. The GVSDT has revised the standard to capture additional ambient condition parameters which could be used for correction in addition to ambient air temperature; however, the requirements are less stringent than required by the RFC standard. As specified by the NERC Rules of Procedure, regional standards can incorporate more stringent requirements than required by NERC, if necessary, for regional reliability. **The SDT did modify the standard to assign responsibility for making ambient condition (including ambient temperature) adjustments to the Generator Owner rather than the Transmission Owner.**		
SERC Dynamics Review Sub-committee	No	This provides all the information needed to allow the TO to rate the machines at whatever ambient temperature may be needed. Per #2, the DRS recommends that TO be changed to TP. In attachment 1 item 3.4, the DRS recommends that "correction factor" be changed to "adjustment method," to allow real power determination at multiple temperatures.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner rather than the Transmission Owner. The language of 3.4 in Attachment 1 was revised to "perform corrections to Real Power for different ambient conditions."		
NERC Staff	No	It is not necessary to specify a temperature for which submitted data should be adjusted because one temperature will not be appropriate for all regions or for all types of studies. Providing the recorded value and a temperature correction factor or correction table is appropriate.
Response: The GVSDT thanks you for your comment. The GVSDT agrees with your comment and has revised item 3.4 in Attachment 1 to: **3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** **• Ambient air temperature** **• Relative humidity** **• Cooling water temperature**		
SERC Generation sub-committee	No	Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to

Organization	Yes or No	Question 3 Comment
		be the same.
Response: The GVSDT thanks you for your comment. The GVSDT agrees that the correction factor methodology could be complex, but also points out that simply accounting for the effects of ambient temperature can be sufficient for long-term planning. The standard currently does not require a complex correction factor methodology because the GVSDT did not identify evidence indicating that use of such a methodology would increase reliability. While the GVSDT agrees with your assertion regarding reactive capabilities, the GVSDT does not believe that the standard needs to incorporate these assumptions; instead believing existing practice is sufficient for compliance.		
Westar Energy	No	We believe data should be submitted to the Transmission Planner as written in the draft of the standard.
Response: The GVSDT thanks you for your comment. The TP is the correct entity and is shown in the requirements and Attachment 1.		
Southern Company	No	The verification data is required by R1.3 and R2.3 to be given to the TP, not the TO. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.
Response: The GVSDT thanks you for your comment. The TP is the correct entity and is shown in the requirements and Attachment 1.		
Tennessee Valley Authority GO	No	Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to be the same.
Response: The GVSDT thanks you for your comment. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
Luminant Power	No	Luminant agrees that ambient test temperature and temperature correction information should be submitted to the appropriate entities. In ERCOT, this would be TOP and BA.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 3 Comment
Lakeland Electric	No	It should be acceptable that the Real Power data collected during credible, high-ambient temperature conditions be used to establish Real Power output limits throughout the year, including during lower temperature ambient conditions. By limiting Real Power output to that determined for high-ambient conditions, system reliability will not be compromised during lower ambient temperature conditions/scenarios.
Response: The GVSDT thanks you for your comment. This standard does not address the issue of Real Power output limits to be used in Real-time operations.		
Associated Electric Cooperative, Inc.	No	There is no simple correction factor that can be provided that will allow correction to other ambient temperatures. If necessary, a special request could be made to the GO/GOP for correction to another ambient temperature.
Response: The GVSDT thanks you for your comment. The GVSDT agrees there is not a simple correction factor that can account for all temperature effects; however, the GVSDT also believes it is not necessary to account for all temperature effects in order to maintain reliability.		
New York Independent System Operator	No	Temperature correction shall be performed as required by the Transmission Operator. The NYISO requires ambient temperature data only for Real Power Tests for combined cycle, combustion, and turbine units.
Response: The GVSDT thanks you for your comment. This is a long-term planning standard, and the data verified under MOD-025 is to be used in planning studies. The SDT modified the standard (Attachment 1, Step 3.4) to assign responsibility for making the ambient condition (including ambient temperature) adjustments to the Generator Owner rather than the Transmission Owner.		
Exelon	No	The Standard needs to address correction factors for "ambient conditions" instead of "air temperature." Specifically, large generating units are typically water cooled and therefore the correction factor should be revised as such. In addition, as stated in the response to question 2 above, the Transmission Planner should be the appropriate entity instead of the Transmission Owner.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change “ambient temperature” to “ambient conditions” and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** **• Ambient air temperature**		

Organization	Yes or No	Question 3 Comment
• Relative humidity • Cooling water temperature		
Tacoma Power	No	Tacoma Power is not aware of any industry accepted standard air ambient real power correction factor for hydro units.
Response: The GVSDT thanks you for your comment. Correction factor consideration does not apply for units that are not affected by ambient temperature effects. The GVSDT will revise standard language to clarify this point.		
Georgia Transmission Corporation	No	The ambient temperature and other factors that influence the output should be included. The GO should provide temperature dependent and other data tables/graphs to the TP. Again, the comment form and attachment seem to conflict with R1 and R2 to provide data to the TP not the TO.
Response: The GVSDT thanks you for your comment. The intent of the standard is for the GO to create a correction factor from the data normally used for such purpose. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner.		
Austin Energy	No	Ambient temperature will have a less direct effect on water cooled generators with cooling water sources not directly affected by ambient temperature.
Response: The GVSDT thanks you for your comment. Item 3.4 in Attachment 1 provides guidance with respect to correction factors (note these have been revised so that the phrase, "ambient temperature" was replaced with the broader phrase, "ambient conditions"): **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
BC Hydro	No	Generating facilities are already designed and ratings determined based on maximum expected ambient temperatures. Besides, equipment cooling may not be directly dependent on ambient temperature. Providing the details to other entities would be of no practical value. GOs have to meet declared capabilities as registered or derate their facilities if needed.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. Temperature correction is more important for some units, such as gas turbines. The GO may omit the correction factor if unit Real Power output is not dependent, or is minimally dependent on, temperature. If the TP does not require temperature correction, then uncorrected data is used.		
Constellation Power Generation	No	Constellation Power Generation (CPG) agrees with this approach.
Response: The GVSDT thanks you for your comment. Please see the proposed revisions which identify a broader scope of ambient conditions and assign responsibility for making adjustments to the Generator Owner rather than the Transmission Owner.		
Indiana Municipal Power Agency	No	The owner or operator of the generating unit should do the temperature correction to a specified temperature as directed. The owner will possess the curves and be better acquainted with the unit's limitation and temperature correction.
Response: The GVSDT thanks you for your comment. The GVSDT believes that the Transmission Planner has unilateral authority for determining the correction temperature used, given the Transmission Planner selects the temperature value used for planning studies. The Generator Owner provides the correction factor so the TP can simply perform the work without having to track and verify the communication exchange that would otherwise have to occur with the GO. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner.		
Chelan County PUD	No	Should only be required if it impacts the data or test performed. For most generation it would not.
Response: The GVSDT thanks you for your comment. The TP has discretion to perform or not perform temperature correction.		
ISO New England	No	We maintain that temperature correction should be performed as required by the Transmission Operator. The standard must ensure that accurate data for gas turbine and combined cycle generators is obtained which can be adjusted to reflect the ambient temperature presumed in Planning Assessments.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. The data collected through this standard is intended for use in long-term planning studies.		
Duke Energy	No	System models are used for reliability purposes beyond planning purposes, which are at best, an educated guess at what the system will look like out in the future. The real time and day ahead models are most significant for assuring reliable system operation. It would seem that if the TP needs model data different than the Transmission Operations needs, the 1st step is for them to define a technical basis for that data.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>Once that is done, then the GO/GOPs can develop numbers that match those conditions. Pmax will vary on ambient temp for some types of generation, lake temps for other types and hydo conditions for those units. Without a defintion of the data based on the studies to be performed, all the GO can do is guess. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT believes that the standard satisfies most of your recommendations. The TP has discretion whether or not to use the correction factor provided, so the GO does not need to know the Transmission Planners intention. Keep in mind this standard is a planning standard, not a Real-time operations standard.</td></tr>
<tr><td>Indeck Energy Services</td><td>No</td><td>No temperature adjustment can be done reliably with real and reactive power. Real Power may be adjusted, but not with reactive. Generator can make the adjustment if there is a nationwide standard. If not, then regional standards will be required to specify the values.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT agrees the temperature correction factor provided is only used for adjusting Real Power values. Item 3.4 in Attachment 1 provides guidance with respect to correction factors:
3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:
• Ambient air temperature
• Relative humidity
• Cooling water temperature</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>No</td><td></td></tr>
<tr><td>Xcel Energy</td><td>No</td><td></td></tr>
<tr><td>American Wind Energy Association</td><td>No</td><td></td></tr>
<tr><td>Wisconsin Electric</td><td>No</td><td></td></tr>
<tr><td>Tri-State Generation and Transmission, In.</td><td>No</td><td></td></tr>
</table>

Organization	Yes or No	Question 3 Comment
Arizona Public Service Company	No	
Salt River Project	No	
PacifiCorp	No	
Northeast Power Coordinating Council	Yes	Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
Response: The GVSDT thanks you for your comment. The GVSDT does not believe there is any difference between historical data and staged test data with regards to this issue. Either set of data should be correctable to a different ambient temperature basis than the ambient temperature value existing at time of recording. Also keep in mind that the Transmission Planner is the entity that decides if data is temperature corrected to a different basis when performing studies. The GO only provides collected data and a temperature correction factor to the Transmission Planner.		
Imperial Irrigation District (IID)	Yes	THE REAL POWER DATA OBTAINED FROM GENERATORS IS BASED ON AMBIENT TEMPERATURE AND ADDITIONAL ENVIRONMENTAL AND SYSTEMATIC CONDITIONS. BECAUSE OF THIS REASON, OBTAINING A CORRECTION FACTOR CORRESPONDING SOLELY TO THE AMBIENT TEMPERATURE FOR CALCULATION OF THE REAL POWER WILL NOT BE AN EFFECTIVE APPROACH. IN ADDITION, DUE TO SEVERAL PARAMETERS AS A FUNCTION OF THE REAL POWER AND THE TEMPERATURE, CALCULATION OF AN ACCURATE CORRECTON FACTOR WOULD BE SOMEWHAT DIFFICULT AND COSTLY AS IT MAY REQUIRE SEVERAL GENERATOR TESTING.
Response: The GVSDT thanks you for your comment. There are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The reason why the GVSDT incorporated temperature correction consideration into the draft standard is because most Planners specify ambient temperature conditions when performing planning case studies. The GVSDT does not intend for entities to perform multiple tests. Instead, the GO simply provides a temperature correction factor with test data collected. As a matter of practicality, temperature correction factor information should already be captured as part of the internal process used for performing Real Power testing.		

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc Affiliates	Yes	The ambient temp and correction factor should be provided to the TP with all the data as stated in Question 2.
Response: The GVSDT thanks you for your comment.		
SPP Reliability Standards Development Team	Yes	We feel that the entity should be the Transmission Planner, but there is a need for the Generator Owner to provide an adjustment factor. The standard should address the temperature to bring the data to and then the Generator Owner could provide the factor to adjust the data. The standard also needs to address the fact that the temperature will not be a single set number and will vary depending on the season and geographic location.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
SERC Planning Standards Subcommittee	Yes	The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. The intent of the temperature correction factor provision is to allow the Transmission Planner make any correction to collected data deemed necessary during engineering analysis. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity**		

Organization	Yes or No	Question 3 Comment
• Cooling water temperature		
Dominion	Yes	We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that compliance with this standard be based solely upon the requirements contained within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Response: The GVSDT thanks you for your comment. The GVSDT has revised the standard to capture additional ambient condition parameters which could be used for correction in addition to ambient air temperature and to change the responsibility for making adjustments from the Transmission Owner to the Generator Owner. Item 3.4 in Attachment 1 provides guidance with respect to correction factors: **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:** • **Ambient air temperature** • **Relative humidity** • **Cooling water temperature**		
Public Service Enterprise Group	Yes	We believe that the Real Power data submitted should be corrected to a temperature specified by the entity that requires the verification of Real Power capability. That entity is probably the Resource Planner or the Planning Coordinator- see the Functional Model, version 5 posted at http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf. For Generation Owners that belong to Regional Transmission organization that has a reserve margin criterion, it is probably registered as a Resource Planner and Planning Coordinator. For example, PJM, NYISO, and ISO-NE are each registered as a Resource Planner and a Planning Coordinator.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. **Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:** **2. Collects information including:**		

Organization	Yes or No	Question 3 Comment
c. Generator unit performance characteristics and capabilities from Generator Owners. **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
South Carolina Electric and Gas	Yes	The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
Response: The GVSDT thanks you for your comment. The GVSDT believes that the Transmission Planner has sufficient flexibility to perform engineering analysis if only a correction factor is provided.		
Cowlitz County PUD	Yes	As long as correction factors may be documented from normal run history, this would not be burdensome to produce. As currently written, MOD-0025-2 appears to allow the Generator Owner to make a judgment call on whether ambient air temperature plays a significant role in generation capacity. If this is the case, then the report form should have a specific question: Is ambient air temperature correction factor applicable? ______ If yes, include in remarks below correction factors for different temperatures. Also, water coolant temperature may play a greater role. A quick passing hot or cool day during testing may not have any effect on the water coolant temperature. Where water temperature has a greater impact on capability, seasonal trends may be of greater significance. Finally, there is no criterion stipulated to define when ambient temperature correction factors are significant and should be provided. Cowlitz suggests that ambient temperature should only be considered significant if it affects Real or Reactive Power capability more than 10% between the lowest and highest expected ambient temperature extremes.
Response: The GVSDT thanks you for your comment. The revised standard (see Requirement R1, Part 1.3) allows the Transmission Planner to use discretion when determining if ambient condition correction is necessary for Real Power verification.		
Northeast Utilities	Yes	Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient

Organization	Yes or No	Question 3 Comment
		temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
Response: The GVSDT thanks you for your comment. The data is not required to be adjusted. The TP is not required to use the correction factor provided.		
Consolidated Edison Co. of NY, Inc.	Yes	Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
Response: The GVSDT thanks you for your comment. The data is not required to be adjusted. The TP is not required to use the correction factor provided.		
American Electric Power	Yes	Again, we believe the question should be associated with the providing of ambient temperature and correction factor information to the Transmission Planner and the Resource Planner rather than the Transmission Owner. We believe the Resource Planner should provide the ambient temperature value, while the Generator Owner should provide the correction.
Response: The GVSDT thanks you for your comment. As noted in the GVSDT responses to Question Number 2, the TP is the correct entity. As revised, the standard requires the GO to supply a correction factor that the TP may use to extrapolate data to the desired temperature required for engineering analysis. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. **Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities:** **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.**		

Organization	Yes or No	Question 3 Comment
5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners. **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
Ingleside Cogeneration LP	Yes	As with question #2, we believe the appropriate recipient of generator verification data is the Transmission Planner, not the Transmission Owner. Secondly, the Generator Owner providing the validation data must also be responsible for any corrections based on ambient temperature - as there may complexities beyond temperature correction factors. In these cases, if the TP performs the calculation, they may otherwise assume more capacity is available in their contingency assessments. The GO should have the option to provide the actual validation results to the TP with a temperature correction factor, but ultimately that decision rests with them. Third, the Transmission Planner must provide the required operating temperature range necessary for their system models. This will assure consistency among generators operating within their planning jurisdiction. If there are any discrepancies between the GO's and TP's expected range of operation, they can work that out through an iterative resolution process - similar to the structure suggested in MOD-026-1 and MOD-027-1.
Response: The GVSDT thanks you for your comment. As revised, the standard requires the GO to supply a correction factor. The GVSDT believes that simply having the GO supply a correction factor for TP discretional use will result in accurate data for planning purposes.		
Manitoba Hydro	Yes	The standard should allow the provision of ambient temperature during the verification be provided to the Transmission Owner as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature if needed OR Real Power data submitted be temperature adjusted to some other than ambient temperature as requested by the TO.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change "ambient temperature" to "ambient conditions" and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **Item 3.4 in Attachment 1 provides guidance with respect to correction factors:** **3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:**		

Organization	Yes or No	Question 3 Comment
• Ambient air temperature • Relative humidity • Cooling water temperature		
Lincoln Electric System	Yes	The Real Power Data should be adjusted based on temperature to indicate what the output for the generating unit would be for peak summer conditions for a summer peaking utility and peak winter conditions for a winter peaking utility. Humidity is also factor that affects the output of units with evaporative cooling as well as the performance of cooling towers. Previously as part of the Mid-continent Area Power Pool our utility was required to submit monthly capacity accreditation of the generating units that was adjusted based on the ten-year average of the high temperature for the peak load day of the month. For the summer months this provided a fairly accurate estimate of the actual generating capabilities of the unit in the summer months. In the winter using the high temperature for the peak day was not quite as accurate, since the peak on the winter day does not usually coincide with the peak temperature for the day, but the ambient high temperature on these days is usually quite low. Even in the shorter months the output data may be beneficial to the Transmission Planner when large units in a region are out for maintenance. It is questionable as to how easy it would be for the Transmission Owner to apply the correction factors to other ambient temperatures if they are only given the temperature at the time of verification test. For gas turbine units without some form of inlet cooling the output may vary by as much as 30 percent from summer to winter ambient conditions. This is a significant amount of generating capacity.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change “ambient temperature” to “ambient conditions” and to assign responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **The GVSDT believes that the Transmission Planner has unilateral authority for determining the correction temperature used given the Transmission Planner selects the temperature value used for planning studies. The Generator Owner provides the correction factor so the TP can simply perform the work without having to track and verify the communication exchange that would otherwise have to occur with the GO.**		
CPS Energy	Yes	Generator owner should perform the correction and determine the temperature value.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **The GVSDT believes that the Transmission Planner has unilateral authority for determining the correction temperature used given the Transmission Planner selects the temperature value used for planning studies. The Generator Owner provides the correction factor so the TP can simply perform**		

Organization	Yes or No	Question 3 Comment
the work without having to track and verify the communication exchange that would otherwise have to occur with the GO.		
Ameren	Yes	The ambient temperature at which the testing is performed would be an important data item. Because of greater familiarity with the equipment and its capabilities, any temperature adjustment to arrive at a different specified real power value should be performed by the Generator Owner. The Transmission Owner/Transmission Planner, who would be performing system modeling and study work, would be the entity most appropriate to specify temperature values for which temperature adjustment factors would be determined. Capabilities at different ambient temperatures need to be provided to meet the modeling requirements of the MMWG, and that the GO and TO should agree on what ambient temperatures to assume for the temperature adjustment.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner. **The GVSDT agrees that the TP is the appropriate entity to determine the temperature correction value used for planning studies. The GVSDT believes that the TP can perform any correction that is needed with the correction factor provided by the GO.**		
Oncor Electric Delivery Company LLC	Yes	Oncor believes that this information should be submitted to the Planning Authority in the ERCOT Region and that they (the Planning Authority) should coordinate with the Generator Owner in the development of any correction factor and the appropriate temperature value that should be used.
Response: The GVSDT thanks you for your comment. The SDT modified the standard (Attachment 1, Step 3.4) to change responsibility for making the ambient condition adjustments to the Generator Owner rather than the Transmission Owner.		
Wisconsin Public Service Corp	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

4. The SDT believes that verification should be performed on units that are connected down to 100 kV. The SDT has also provided how verification should be handled in plants/Facilities that are greater than 75 MVA in aggregate gross nameplate rating. The Standard requires a separate verification for every unit greater than 20 MVA gross nameplate rating, this is consistent with the current Compliance Registry. Units 20 MVA and smaller, in a plant/Facility greater than 75 MVA can be verified separately or in aggregate as the Generator Owner chooses. Do you agree with the SDT's decision to have the standard be applicable to the compliance registry? If not, please explain.

Summary Consideration: A majority of stakeholders disagreed with making the standard applicability match the same Facility thresholds as specified in the compliance registry. Several stakeholders suggested that the applicable generator size should be 75 MVA, or determined by the Planning Coordinator for its planning area or Interconnection (as specified in other proposed standards). Several stakeholders also suggested that the "sister" unit concept should be allowed for essentially identical units to minimize the number of units tested. Multiple stakeholders suggested referring to the Registry Criteria instead of restating Registry Criteria in the standard in the event criteria changes at a later date. A few stakeholders suggested that generator applicability should be independent of the voltage at the point where the unit is connected. None of the suggestions received include strong justification for having standard applicability deviate from the Compliance Registry, thus the SDT did not change the thresholds in the applicability of the standard.

Several commenters suggested that the applicability of this standard should mimic that of MOD-026 and MOD-027. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response, while MOD-025 verifies capability. The same basis does not apply.

Blackstart units were removed from the applicability because of redundancies with the requirements of EOP-005-2

R1.4. Identification of each Blackstart Resource and its characteristics including, but not limited to, the following: The name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

R6. Each Transmission Operator shall verify, through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations, or testing shall verify: [Violation Risk Factor = Medium] [Time Horizon =Long-term Planning]

R6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.R9. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include:

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

R9.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

R9.2. A list of required tests including:

R9.2.1. The ability to start the unit when isolated with no support from the BES, or when designed to remain energized without connection to the remainder of the System.

R9.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus, such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

R9.3. The minimum duration of each of the required tests.

Organization	Yes or No	Question 4 Comment
LG&E and KU Energy	No	Blackstart unit testing is covered in he EOP standards, and should not be included in the MOD standards. Most of these are smaller units that don’t have much impact on the BES but are important because they are blackstart-not for the VARs.
Response: The GVSDT thanks you for your comment. VAR testing is important for line charging when considering small black start units.		
Northeast Power Coordinating Council	No	Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. Please see the response to Question 2.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	There may be generating units or facilities that are included or excluded as BES elements either by the latest BES definition or the latest BES exception procedure that differ from 4.2.1 and 4.2.2. So we recommend adding anItem 4.2.4 to the Applicability section that states, “Generating Facility, generating unit or synchronous condenser that are designated as a BES Element according to the BES definition or BES exception procedure.”
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Cowlitz County PUD	No	The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Cowlitz is not convinced that the Standard be applicable to the compliance registry of Generator Owners. For example, an entity owning a single small 500 KVA generation plant currently is exempt from registration; however it may own a transmission protection system protecting a BES element from a fault originating on the high side of the step up transformer. Therefore it should register as it is material to the reliability of the bulk power system. From the extensive reference of 20 MVA and 75 MVA in the Standard from the Compliance Registry Criteria, it appears that the SDT would not see a need for the 500 KVA generation plant to verify its capability. Further, pointing to the Compliance Registry Criteria’s generator MVA name plate ratings is also questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. After reviewing the Field Test

Organization	Yes or No	Question 4 Comment
		Results, Cowlitz finds that WECC set the line at 10 MVA and SERC recommended 75 MVA with no substantiating arguments. Also noted in the Field Test Results was a problem in getting the dynamic models to return data results that agreed with actual events. With the Field Test Results dated in 2007, Cowlitz is unsure on the current accuracy of dynamic model predictions. However, if models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Looking over the data requirements of MOD-25, Cowlitz can see that there will be considerable consultant cost - $25,000 - to comply. Using the Compliance Registry Criteria for applicability is not acceptable. Unwarranted compliance efforts will reduce overall reliability results. Cowlitz recommends the SDT consult with Planning Coordinators (Planning Authorities) and Transmission Planners on the current status of modeling accuracy and request documentation for generation that can be ignored. Also, it may be permissible for smaller generation to simply report seasonal historical Real and Reactive Power output.
Response: The GVSDT thanks you for your comment. MOD-025 calls for verification of static points that the unit is capable of reaching. Transmission or unit equipment limitations may prevent a unit from reaching its design basis. As generating equipment ages, its operating characteristics change. Over time, unit performance degrades unless upgrades to the unit are made. In order to ensure that planning models have accurate, dependable data, verifications need to be performed. The GVSDT has no basis to exclude any units included in the registration criteria from testing. The GVSDT also believes that a five-year testing interval would not be a burden.		
SERC Planning Standards Subcommittee	No	The use of sisters units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability. However, the standard should apply to designated blackstart units included in a system restoration plan, regardless of size.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Ameren	No	The allowance for exemption of sister units should be permitted. Only one verification for sister units should be required. Testing for units less than 75 MVA should not be required, as these have little impact on grid reliability.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Indeck Energy Services	No	Some standards need to apply to all registered generators. These do not. The minimum unit size should be at the NERC Reportable Disturbance level for the control area. Variations in any other sized unit need not

Organization	Yes or No	Question 4 Comment
		even be reported. This isn't about treating all generators fairly, it is about what is affecting BPS reliability.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Chelan County PUD	No	For multi-unit hydro and wind plants this can become a large effort. A "type" test where one of an identical family of units is verified is more practical and should provide sufficient data.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Santee Cooper	No	Recommend changing Section 4.2 Facilities to match Section 4.2 Facilities as it is written in MOD-026-1 and MOD-027-1 below: 4.2. Facilities For the purpose of this standard, the following Facilities are considered, “applicable units.” Units or plants with an average capacity2factor greater than 5% over the last three calendar years that meet the following: 4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics: o Each generating unit with a gross nameplate rating greater than 100 MVA, connected at the point of interconnection3at greater than 100 kV. o For each plant with a gross aggregate nameplate rating greater than 100 MVA, connected at the same point of interconnection at greater than 100 kV: o Each unit with a gross nameplate rating greater than 20 MVA; and o The remainder of the plant as an aggregate. There should also be some allowance for Units which are nearly identical and therefore model the same.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn’t address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response while MOD-025 verifies capability. The same basis does not apply.		
PPL Generation	No	The applicability of this standard should include, "and having a capacity factor for the past three years averaging over 10%." As presently written this standard would require VAR testing of a small, emergency genset if located in a baseload facility interconnected greater than 100 kV.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. The GVSDT believes that a five-year testing frequency is reasonable for any unit. The GVSDT does not believe that emergency generators are connected at 100 kV and would therefore not be included. The GVSDT believes that when the capacity is needed the most and therefore most critical to reliability is the time when these units would be running, and, therefore, should be verified.		
SERC Dynamics Review Sub-committee	No	The use of sister units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
NERC Staff	No	While we agree that all units connected at voltage <100 kV need not be tested and modeled, any units >20 MVA and plants/facilities >75 MVA should be tested and modeled accurately regardless of interconnection voltage. The reliability impact of generating units is more directly related to unit capability than interconnection voltage.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
SERC Generation sub-committee	No	We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentially identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response while MOD-025 verifies capability. The same basis does not apply.		

Organization	Yes or No	Question 4 Comment
Black start units were removed from applicability because they are addressed in EOP-005, as you suggest.		
Arizona Public Service Company	No	Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of the BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
Southern Company	No	We believe that Section 4 Applicability for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. However, for plants with a gross aggregate nameplate rating â‰¥ 100, we question the need to perform verification for individual units as small as 20 MVA. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for verification of units as small as 20MVA needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their criticality to the system seems to be inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response while MOD-025 verifies capability. The same basis does not apply.		
Tennessee Valley Authority GO	No	We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentialy identical units should not be required.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may be made to the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. The SDT believes that the applicability is different because MOD-026 and MOD-027 verify dynamic response, while MOD-025 verifies capability. The same basis does not apply.		
South Carolina Electric and Gas	No	The verification of sisters units on an alternating basis should be allowed by the standard.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Associated Electric Cooperative, Inc.	No	The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERCs current MOD-025 regional criteria). Independent verification of essentially identical units should not be required.
Response: The GVSDT thanks you for your comment. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Tacoma Power	No	1) Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. 2) Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity.
Response: The GVSDT thanks you for your comment. The terms, "gross unit nameplate" and "aggregate gross nameplate" are not used in the standard. The GVSDT has no basis to exclude any units included in the registration criteria from testing.		
BC Hydro	No	In principle, using compliance registry as a sole criteria for applicability of Reliability Standards removes technical evaluation and justification from the process. The value that technical experts participating in SDTs may add becomes limited, which ultimately does not benefit the industry.
Response: The GVSDT thanks you for your comment. The GVSDT agrees but has no basis to exclude any units included in the registration criteria		

Organization	Yes or No	Question 4 Comment
from testing.		
Northeast Utilities	No	Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing. This standard may have to be revised if the registry criteria changes.		
Constellation Power Generation	No	Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. This standard may have to be revised if the registry criteria changes.		
Consolidated Edison Co. of NY, Inc.	No	Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by BES SDT.
Response: The GVSDT thanks you for your comment. The GVSDT has no basis to exclude any units included in the registration criteria from testing. This standard may have to be revised if the registry criteria changes.		
Duke Energy	No	Obviously, all units which are critical to reliability should be included, but what is critical is dependent upon system configurations. The continent wide standard should specify the largest size units critical in an interconnection and then regional standards might tighten the number based on that region's need. The SERC region currently requires real & reactive verification only for units > 75 MVA (RFC uses 85 MVA). The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentialy identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. Any testing performed for Blackstart Resources under the EOP standards may be used to show compliance with the MOD-025 standard for similar requirements. Additional or separate testing is not required. The GVSDT also believes that a five-year testing frequency is reasonable for any unit. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.		
Independent Electricity System Operator	No	The Applicability section is not clear enough to expect consistent application. When the facility that makes the connection at 100 kV or above is not owned by the Generator Owner (e.g. a Distribution Provider might own this facility) the present expression of the standard will lead to inconsistencies. Facilities with identical electrical characteristics may or may not be subject to this standard only because of the structure of the ownership of assets. To address this, we propose revising section 4.2 by removing the condition for interconnection at 100 kV and above and aligning with the standard's purpose:4.2.1 Individual generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating) considered in BES reliability assessments.. 4.2.2 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) considered in BES reliability assessments.4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.
Response: The GVSDT thanks you for your comment. The GVSDT has revised the applicability to be consistent with NERC Compliance Registry Criteria and other standards being developed under this project: **For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:** **4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) in a directly connected to the bulk power system.** **4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.** **4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.**		
Indiana Municipal Power Agency	Yes	IMPA supports the SDT's decision to have the standard be applicable to the compliance registry.
Response: The GVSDT thanks you for your comment.		
Idaho Power-Power Production	Yes	Consistency with the compliance registry and the BES definition is important.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment.		
FirstEnergy	Yes	We agree that this standard should be consistent with the NERC Compliance Registry.
Response: The GVSDT thanks you for your comment.		
Westar Energy	Yes	We propose that language be added to reference the Compliance Registry to ensure that as the Registry changes the appropriate applicability is followed.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria, but were directed by NERC to state it as it is currently shown. If the registry criteria changes then changes may be made to the standard.		
SPP Reliability Standards Development Team	Yes	If the intent is that the team wants to follow the Compliance Registry then we would ask that there be direct language reference to the Registry. If this isn't done and the Registry changes as worded now the standard would be static to the numbers given. This team needs to get plugged into the BES DEF standard drafting team as there are discussions being held currently that could change the Registry criteria.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers. If the registry criteria changes, then changes may need to be made to the standard.		
Ingleside Cogeneration LP	Yes	These applicability criteria are consistent within the Regions that Ingleside Cogeneration has familiarity with (TRE, WECC, and SERC).
Response: The GVSDT thanks you for your comment.		
ISO New England	Yes	Yes, however the standard should not rewrite the Compliance Registry as attempted in section 4.2. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry's wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity's restoration plan. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers.		

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	Yes	The Applicability of this standard should be to BES Generating Units and Facilities. Section 4.2 should not restate components of the proposed BES definition.
Response: The GVSDT thanks you for your comment. The GVSDT at one point used direct language referencing the registry criteria but were advised by NERC to state it as it is currently shown because the compliance registry doesn't address ownership of synchronous condensers.		
Imperial Irrigation District (IID)	Yes	
Pepco Holdings Inc Affiliates	Yes	
Dominion	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	
Luminant Power	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Lakeland Electric	Yes	

Organization	Yes or No	Question 4 Comment
Exelon	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
American Electric Power	Yes	
Wisconsin Public Service Corp	Yes	
CPS Energy	Yes	
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Response: The GVSDT thanks you for your comment.		

5. The draft standard requires that the Reactive Power capability be verified at four points: Over-excited (lagging) and under-excited (leading) Reactive capability at (1) the rated Real Power capability and (2) expected minimum Real Power output. The SDT believes that this is consistent with the FERC directive in Order 693 at P1321, "Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of Reactive Power capability at multiple points over a unit's operating range." Do you agree that the four points proposed by the SDT is adequate to provide a straight line approximation to a unit's Reactive Power capability over its actual operating range? If not, please explain.

Summary Consideration: A majority of stakeholders agreed that the four points proposed by the SDT are adequate to provide a straight-line approximation to a unit's Reactive Power capability over its actual operating range. Some stakeholders suggested testing less than four points (i.e. only Pmax, Qmax for nuclear units), while others suggested not testing at all. The SDT agrees that the four points proposed will provide an adequate approximation of the machine's capability and satisfy the directive in Order 693. For units that have environmental or other legally-bound restrictions, the standard does not require violating those restrictions. If a unit has no leading capability, then it should be reported with no leading capability. This statement was added as Note 4 of Attachment 1:

Note 4: The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability, or the minimum lagging capability at which it can operate.

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		The addition of the lagging and leading at (2); the expected minimum Real Power output are new points to test from the existing version of MOD-025. This will eventually double the testing window (at a minimum)
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply

Organization	Yes or No	Question 5 Comment
		with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. See response to Question 2.		
SPP Reliability Standards Development Team	No	This is a non linear curve. Is the reason for using the 4 point method all that would fit into the model? We also have the concern that isn't addressed here and it is if the unit can't be tested at the time due to system conditions then you must wait until the system is able. We feel that the points should reflect what is usable.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Although the GVSDT does not believe that engineering analysis alone is sufficient, it is envisioned that engineering analysis may be used to supplement operational data or staged testing. The following Note was added to Attachment 1 of the standard: **"While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system conditions. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling."**		
Idaho Power-Power Production	No	No, we believe that the four points are not adequate to describe a unit's capability. FAC-008 and FAC-009 require us to have a normal and emergency rating and the WECC validation policy requires the verification of the unit's capability. Is this standard intended to replace those standards/policies? If so it was not clear in the project documentation. If not, we believe this standard to be redundant to our existing policies and procedures here in WECC.
Response: The GVSDT thanks you for your comment. MOD-025-2 is not intended to replace FAC-008 or FAC-009. The FAC standards relate to a Facility ratings methodology while MOD-025 is a verification of actual performance. It is possible that the required performance in this standard may satisfy the WECC validation policy.		
Santee Cooper	No	The current SERC Regional Criteria requires gross and net reactive capability be determined within the power factor range at which the generating equipment is normally expected to operate. We do not believe anything is gained by testing in power factor ranges where the unit is not expected to operate.
Response: The GVSDT thanks you for your comment. The GVSDT disagrees. The full reactive capability range must be known for planning purposes.		
Dominion	No	We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that

Organization	Yes or No	Question 5 Comment
		compliance with this standard be based solely upon the requirements contained within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Response: The GVSDT thanks you for your comment. As now stated, the revised standard requires that sufficient data be taken to allow correction to conditions other than ambient, if requested. This requirement addresses one of the directives in FERC Order 693.		
FirstEnergy	No	As a TO, we rank the importance to the modeling effort as follows: (1) Pmax, Qmax; (2) Pmin, Qmin; (3)) Pmax, Qmin. We believe that the Pmin, Qmax is of little value to a Planning Engineer.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
NERC Staff	No	Reactive Power capability is not a linear function of Real Power. The reactive capability curve and minimum excitation limiter settings for each machine should be used to determine the expected gross reactive capability.
Response: The GVSDT thanks you for your comment. The GVSDT concurs that reactive capability is not a linear function of Real Power. However, MOD-025-2 is a performance-based standard which is to verify the Real and Reactive power capabilities of generators.		
Public Service Enterprise Group	No	For clarification, Attachment 1, paragraph 2.2 does not require Reactive Power capability verification for wind and photovoltaic at minimum Real Power output. It also appears that Nuclear Units are also exempt. “Nuclear Units” has the term “Units” capitalized, but it is not in the NERC Glossary and should probably be lower case. We suggest that R2.2 be redrafted as follows: “Verify Reactive Power capability of all generating units other than nuclear, wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. In addition, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. This would require a change in paragraph 2.1For other units, these points are acceptable.
Response: The GVSDT thanks you for your comment. The GVSDT believes that if a nuclear plant has under-excited capability, it should be tested within the unit’s capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, “Auxiliary bus voltage limits should be observed.”		
SERC Generation sub-committee	No	Although we agree that four points are sufficient to provide a straight line approximation over a unit's

Organization	Yes or No	Question 5 Comment
		operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load.Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well.This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, The GS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other legally-bound restrictions, the standard does not require violating those restrictions. If a unit has no leading capability, then it should be reported with no leading capability. This statement was added as Note 4 of Attachment 1: **Note 4: The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability or the minimum lagging capability at which it can operate.**		
Southern Company	No	We agree that four points are sufficient to provide a straight line approximation over a unit's operating range. However, we strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." Paragraph 1321 of the FERC Order states, "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." These statements indicate the Commission is seeking further guidance from the industry. Based on this, we have the following recommendations. First, we believe 2.2 of Attachment 1 to the standard should exempt all base load units, not just nuclear units, from verification of reactive capability throughout the full MW range. There are other units the industry should be able to justify exempting based on their normal operating modes.

Organization	Yes or No	Question 5 Comment
		Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) that prevent operation at minimum load. Second, we suggest that an evaluation be made on a small subset of units that could then be used to respond to the question raised by FERC. Our experience indicates that a unit will typically be capable of delivering or absorbing a comparable amount of reactive power to/from the grid at minimum load when compared to full load. The industry as a whole does not need to perform the verification at multiple points on 100% of the units to respond to an open question from FERC. Third, for units where verification of multiple points are needed, the analytical approach to verification we discuss in our responses to Questions 10, 11, and 14 serves this purpose very well.
Response: The GVSDT thanks you for your comment. The drafting team believes that four test points represent the minimum number required to meet the FERC directive of testing multiple points throughout the Load range to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other restrictions, the standard does not require violating those restrictions.		
Tennessee Valley Authority GO	No	Although we agree that four points are sufficient to provide a straight line approximation over a unit's operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary."First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification, discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states:"...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary."Also, We do not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Response: The GVSDT thanks you for your comment. The drafting team believes that four test points represent the minimum number required to meet the FERC directive of testing multiple points throughout the Load range to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for		

Organization	Yes or No	Question 5 Comment
other base Load units. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other restrictions, the standard does not require violating those restrictions.		
Luminant Power	No	Luminant proposes the following: 1. At High Load - Maximum overexcitation and under-excitation testing shall be conducted at a minimum of 95% of real power output capability and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 2. At Low Load - Maximum overexcitation and under-excitation testing shall be conducted in the output range between minimum stable load and minimum stable load plus 30%, and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 3. Lead and lag tests can conducted independently.
Response: The GVSDT thanks you for your comment. The GVSDT believes that the Loads required for testing are safe and adequately described. Wording has been changed to better define tests derived from historical data in Requirements R1-R3 and Item 2 in Attachment 1. **Lead and lag tests can be conducted independently.**		
PacifiCorp	No	PacifiCorp believes that the four points proposed by the SDT are adequate with respect to thermal and hydro generation units; however, the proposed points do not adequately take operating conditions for wind generation facilities into consideration.
Response: The GVSDT thanks you for your comment. The GVSDT welcomes suggestions relative to testing wind generation facilities.		
Associated Electric Cooperative, Inc.	No	We don't agree that four points are needed for baseload units, since they are rarely expected to operate at or near Pmin. In addition to nuclear units, baseload units should be exempt from reactive capability verification at Pmin.
Response: The GVSDT thanks you for your comment. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units. Testing nuclear units at P min is not required by the standard.		
New York Independent System Operator	No	There is no value to performing the lagging testing at minimum real power loading and leading test at maximum power. The testing requirement should be changed to two test points. One test for an hour to

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner; a second test to verify under-excited capability (leading) at the real power level specified by the Transmission Operator or the Transmission Planner.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.</td></tr>
<tr><td>Cowlitz County PUD</td><td>No</td><td>Cowlitz answers “no” in that the question does not address if the data is truly going to be used. The SDT should confer with Transmission Planners requesting specifically how they will implement such data and if it will result in better modeling results. Data collection that will not be used is wasted compliance effort. FERC also seems to be confused as to the purpose of the Standard when it states “[t]he capability of generators to produce reactive power is essential for real-time analysis” rather than system modeling and planning. Based on this, should the reactive capability data also be sent to the Balancing Authority? If the SDT has technical foundation to refute FERC’s directive then it should be communicated. The Standard can be written as FERC demands, but with a recommendation that the requirement be removed.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT has no technical foundation to refute the FERC directive in Paragraph 1321, which states:

“1321. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce Reactive Power is essential for Real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify Reactive capability only at the unit’s full MW Loading. However, other than base Load units, most generating units rarely operate at full MW Loading. It is unclear what Reactive capability is available throughout a unit’s Real Power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit’s Real Power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit’s operating range.”

Regarding the Balancing Authority: As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (VP, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
Planners, and other Transmission Planners. **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
Exelon	No	Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Suggest the following revision to Attachment 1 as follows:2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.
Response: The GVSDT thanks you for your comment. If a nuclear plant has under-excited capability, it should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, "Auxiliary bus voltage limits should be observed."		
Georgia Transmission Corporation	No	Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability.
Response: The GVSDT thanks you for your comment. Engineering analysis is allowed and encouraged to supplement testing and gain a better picture of the plant's reactive power capability.		
Great River Energy	No	GRE doesn't agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load. If they want it at different points I think they should leave it up to the GO/GOP's to decide at what other load point they want to run the test.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Low Load verification is required at the "minimum Real		

Organization	Yes or No	Question 5 Comment
Power output at which the unit is normally expected to operate.”		
BC Hydro	No	Technically, only verification at the maximu rated active power output has practical value since it is the most limiting operating condtion in terms of reactive power capability.Verifying reactive power capability at lower active power outputs is redundant because: 1. The capability will obviously be somewhat higher than at maximum active power output 2. Registration data normally include only Qmax and Qmin, which are determined at unit's rated active power output. 3. Reactive capability does not depend on unit's active power output as much as on other factors, such as system or station service voltagesD-curve is developed based on calculated data. The purpose of this should not be verification of the curve
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
ISO New England	No	Performing testing for lagging capability at minimum real power output especially would require an inordinate amount of planning to ensure that transmission voltage levels in the local area are not exceeded. Testing requirements should be changed to two points, one for an hour to verify over-excited reactive capability at rated Real Power and one at minimum Real Power output to verify under-excited capability. Also the test of leading capability at minimum real power loading should be held for five minutes. These tests are adequate to verify critical characteristics of the generator for use in studies. The four point tests may be difficult to obtain given system configuration and operation.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. The GVSDT recognizes that limitations may inhibit being able to achieve the desired testing levels. Any limitations should be entered in Attachment 2, “Remarks”. The note states: “If the verification value did not reach the Thermal Capability Curve (D-Curve), describe the reason”. This could include transmission system limitations.		
Independent Electricity System Operator	No	One of the purposes of Project 2007-09 is to ensure that generator models accurately reflect the generator’s capabilities and operating characteristics. To achieve this, it is important that at least the minimum data requirements of entities that require these data are satisfied. This includes verifying the generating unit’s capability curve or at least that portion of the curve between its minimum and maximum real power capability. We therefore recommend including a new bullet 2.3 in MOD-025 Attachment 1 similar to bullet 2.1 that requires verification of Real and Reactive Power capability of all generating units at maximum over-excited

Organization	Yes or No	Question 5 Comment
		and under-excited reactive capability at maximum gross Real Power capability (PMAX) where this is different from the generating unit's rated gross Real Power capability. The additional data points provided by this measurement (i.e. Qmax and Qmin at PMAX) will allow for a more complete verification of the generating unit's capability curve. Footnote 1 of MOD-025 Attachment 1 seems to use "rated gross Real Power" and "maximum [gross] Real Power" interchangeably. In general these two ratings may be different. We suggest deleting the footnote.
Response: The GVSDT thanks you for your comment. The GVSDT disagrees that testing at values above Pmax is needed to approximate the Reactive capability. Testing at additional points, however, is not prevented by the standard. The footnote was deleted, as you suggested.		
Ameren	No	While the testing regimen for the generator owners should not be made unduly burdensome, the four point test, if used to provide a straight line approximation of the generator capability, could result in somewhat more conservative reactive power operating limits for other real power levels as compared to a generating unit's published capability curve. The accuracy of the straight line approximation would vary on a generator-by-generator basis.
Response: The GVSDT thanks you for your comment. While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling		
Indeck Energy Services	No	We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, we not believe that verification for leading capability should not be required where operational practices preclude operation in a leading mode. Finally, for units where verification of multiple points are needed to satisfy the FERC directive, we agree that 2 points are sufficient to verify the lagging capability and 2 points are sufficient to verify the leading capability

Organization	Yes or No	Question 5 Comment
		across the generator MW operating range. However, trying to represent that with a straight line approximation between the two points could eliminate a large portion of the available capability curve around rated pf when rated MW for the unit falls within the stator rating segment of the capability curve, especially when it approaches the stator limit (which can occur for some units).
Response: The GVSDT thanks you for your comment. The drafting team believes that four points represents the minimum number required to meet the FERC directive of multiple test points throughout the Load range to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units. Analytical methods do not provide verification of equipment capability. The standard requires testing at the minimum Load that a unit is normally expected to operate. For units that have environmental or other restrictions, the standard does not require violating those restrictions.		
Oncor Electric Delivery Company LLC	No	Unit reactive capability is limited by many factors and cannot be estimated using a straight line approach, a region of reactive capability over various power levels using actual operating limits is more realistic.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve and that this is a reasonable approximation. Additional testing, while not required, is allowed.		
Indiana Municipal Power Agency	No	IMPA believes that four point testing is excessive and that only two points need to be verified. Those two points would be over-excitged (lagging) and under-excited (leading) reactive capability at the rated Real Power capability only. The two points verified at the expected minimum Real Power output is excessive. Reactive power support happens when load is high and generating units are running at maximum Real Output capability.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
Chelan County PUD	Yes	It is adequate, but variation from testing at the extremes should be permitted due to conditions - in some applications it is difficult to go to full buck or boost without absorbine/providing the reactive power from another unit without impacting the voltage schedule. Should testing cause the voltage schedule to be violated (or worse an unacceptable voltage condition), what should govern? It is unreasonable to expect that every plant over 75MVA can go to these conditions and hold them for an hour.
Response: The GVSDT thanks you for your comment. While not required by the standard, it is desirable to perform engineering analysis to determine		

Organization	Yes or No	Question 5 Comment
expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Imperial Irrigation District (IID)	Yes	WE BELIEVE THAT FOUR POINTS IS SUBSTANTIAL INFORMATION FOR STRAIGHT LINE APPROXIMATION AS OVER-EXCITED (LAGGING) AND UNDER-EXCITED (LEADING) REACTIVE CAPABILITY AT RATED REAL POWER WOULD SOLELY BE A SUFFICIENT DATA FOR THIS PURPOSE.
Response: The GVSDT thanks you for your comment.		
PPL Generation	Yes	The proposed verification at multiple points over a unit's operating range appears to derive from a belief that the verification test results will follow the generator OEM's D-curve; and, owing to the abnormal voltages created by VAR testing and aux bus drop-out limitations; this will not be the case.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
SERC Dynamics Review Sub-committee	Yes	These 4 points should provide adequate testing of the generator. The DRS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Response: The GVSDT thanks you for your comment. The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability or the minimum lagging capability at which it can operate. This has been added to Attachment 1, Note 4.		
Constellation Power Generation	Yes	CPG agrees that the points chosen would provide a sufficient approximation of a unit's capabilities. However, these capabilities will never match a generator's capability curve for a multitude of reasons, and as such, some verbiage should be included in the attachment under item 2 instead of as a note at the end of the document. Further, the limitations on the unit that may not allow the unit to perform to its capability curve are most likely designed into the control system as limiters or protection system components so as to not allow damage to the unit. These designed controls should not be "investigated for resolution" as stated in Note 1.
Response: The GVSDT thanks you for your comment. The standard doesn't require a unit to reach the capability curve value. The capability curve does not reflect all unit limitations that may exist. The limitation that is reached should be recorded on Attachment 2 in the remarks section. The limitations that you suggest are some of those expected to be identified with this standard. Item 2.1 has had the language "the generating unit's		

Organization	Yes or No	Question 5 Comment
normal (not emergency) expected maximum Real Power at the time of verification" inserted in the text rather than being included as a footnote. **The language in Attachment 1 Note 1 was changed to: "Could be further analyzed for resolution." If the limitation is by design, then no further investigation is necessary.**		
American Electric Power	Yes	The results of the test may not accurately reflect the VAR capability due to system conditions or alarm stopping the test and not reflect the actual generator limit in a real time scenario. This is discussed in Notes 1 and 2 of Attachment 1.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	These operating points are more than sufficient to validate reactive capability in accordance with FERC's directive. However, Ingleside Cogeneration LP believes that it is sufficient and far less risky to perform the validation at the TOP's reactive capability schedule limits. In addition, there needs to be an allowance for known equipment limitations which prevent testing at the four test points. Similarly, unforeseen limitations which are determined during testing may prevent the validation at every extreme.
Response: The GVSDT thanks you for your comment. Note 1 of attachment 1 discusses limitations: **Note 1: Under some Transmission System, conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc. which could be further analyzed for resolution. Observe auxiliary bus voltage limits. The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner's database; nor is it likely this value will agree with data required to be submitted by MOD-010.** **Any known equipment limitations should be entered in Attachment 2, "Remarks." The note states: "If the verification value did not reach the Thermal Capability Curve (D-Curve), describe the reason."**		
Duke Energy	Yes	We agree that four points are sufficient to provide a straight line approximation over a unit's operating range at points from Pmax and below, but additional consideration is needed for operation above Pmax. We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." The lagging capability curves have a break at rated pf. Trying to represent that with a single line with end point at Pmin and Pmax would eliminate a large portion of the available capability curve around rated pf. The leading capability might be more reasonably estimated by a linear assumption. Technically, nuclear units are base load plants as are some very large coal units and thus would not be expected to operate for any significant period of time at pmin, thus the term base

Organization	Yes or No	Question 5 Comment
		load is more appropriate than nuclear for excluding testing at Pmin First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load.Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well.This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary."
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Nuclear units are exempted from Reactive Power testing at low Real Power levels to minimize risks associated with changing reactor power levels. These same risks are not present for other base Load units.		
Northeast Power Coordinating Council	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SERC Planning Standards Subcommittee	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Salt River Project	Yes	
Tri-State Generation and Transmission, In.	Yes	

Organization	Yes or No	Question 5 Comment
Dynegy Inc.	Yes	
South Carolina Electric and Gas	Yes	
Xcel Energy	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Wisconsin Public Service Corp	Yes	
Manitoba Hydro	Yes	
CPS Energy	Yes	
Gainesville Regional Utilities	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

6. Verification of over-excited reactive capability at rated Real Power Capability is required to be conducted over a minimum of one hour. Do you agree with the verification time? If not, please explain.

Summary Consideration: The overwhelming majority of stakeholders agree with the one-hour verification period. Several of the stakeholders who disagreed with the one-hour verification time suggested that we revise the verification time period to 15 minutes, 30 minutes, or two hours. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. Some commenters suggested that one hour was not long enough to assure that temperatures have stabilized and that the unit capability is sustainable. The Standard has been modified in Attachment 1, 2.3 to say,

> "Conduct the maximum Real Power and overexcited Reactive Power verifications required in 2.1 for a minimum of one continuous hour."

Organization	Yes or No	Question 6 Comment
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. Please see response to Question 2.		
SPP Reliability Standards Development Team	No	Currently SPP has criteria that the testing period should be 15 minutes rather than the listed 1 hour. We have found that this time period is adequate.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the		

Organization	Yes or No	Question 6 Comment
standard.		
Idaho Power-Power Production	No	No, if this is intended to verify an emergency reactive capability we believe 15 minutes is sufficient. If this is intended to verify a normal reactive capability then 1 hour is reasonable.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. The standard is aimed at verification of normal reactive capability.		
PPL Generation	No	The one-hour period appears to derive from D-curve (thermal limiting) expectations; and, as explained above, this will not be the case
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
NERC Staff	No	Often, on larger units, temperatures do not stabilize within one hour. It is important for this test to assure that temperatures have stabilized and that the unit capability is sustainable, so the overexcited reactive capability test should be conducted for a minimum of two hours or until the temperatures have stabilized.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. Attachment 1, 2.3 states: **"Conduct the rated Real Power and overexcited Reactive Power verifications required in 2.1 for a minimum of one continuous hour.** **It is up to the entity testing the unit to determine when the temperatures are stable."**		
Arizona Public Service Company	No	30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability		

Organization	Yes or No	Question 6 Comment
that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
PacifiCorp	No	First, PacifiCorp believes that over-excited reactive capability at rated Real Power verification should be performed on the same basis as for under-excited reactive capability and over-excited reactive capability at expected minimum Real Power output - that such data should be recorded as soon as a limit is reached. Second, this does not adequately take operating conditions for wind facilities into consideration.
Response: The GVSDT thanks you for your comment. The GVSDT believes that a stabilization period is needed to assure that verified data is sustainable. The GVSDT also believes that the rated power lagging test is the most demanding so that extended operation at other test points would not be required. Item 2.1 was revised in Attachment 1 to provide better clarity around testing requirements for wind facilities. **"If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold. Maintain as steady as practical Real and Reactive Power output during verifications."**		
Cowlitz County PUD	No	Cowlitz suggests that "rated" be replaced with "normal expected maximum" in requirement 2.1 and "maximum" in requirement 2.3; although the footnote makes the intent clear, there is no need to complicate the reading of the Attachment and effectively redefine the normal understanding of the word rating. As far as running the test at least one hour, this commenter is not sure how quickly a unit achieves thermal stability. Again, Cowlitz questions if the data will be used and its actual contribution to improved modeling and future planning.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the revision Attachment 1, Item 2.1 has had the language "the generating unit's normal (not emergency) expected maximum Real Power at the time of verification," inserted in the text rather than being included as a footnote. Attachment 1, item 2.3 was revised as suggested.		
Xcel Energy	No	Southwestern Power Pool testing criteria specifies a 15 minute hold point and WECC requires holding until the temperatures are stable, which has always been less than one hour. We believe one hour is excessively long, and instead recommend a 15 minute verification time.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard. Some commenters suggested that one hour was not long enough to assure that temperatures have stabilized and that the unit capability is		

Organization	Yes or No	Question 6 Comment
sustainable. The Standard has been modified in Attachment 1, 2.3 to say: "Conduct the maximum Real Power and overexcited Reactive Power verifications required in 2.1 for a minimum of one continuous hour."		
Manitoba Hydro	No	To obtain more realistic rated real power and over-excited reactive power ratings, the minimum verification time should be 2 hours or until temperatures have stabilized. For under-excitation, the test duration should be 1 hour.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
CPS Energy	No	30 minutes should be sufficient time to verify capability.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Gainesville Regional Utilities	No	We suggest 30 minutes. While it may take an hour to reach full stabilized temperatures the probability of being called to perform form greater than 30 minutes is remote.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Chelan County PUD	No	What is the basis for an hour? It should be tested to demonstrate stability at that point and not trip. After that why stay at an extreme condition? If you are concerned about MVA verification that can be done at any value, certainly design output and power factor is a better point.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		

Organization	Yes or No	Question 6 Comment
Tacoma Power	No	Depending on the size of the unit and location in the transmission system operating the unit at full rated reactive capability with normal steady state transmission voltages may subject the plant and transmission system to a sustained overvoltage. The over-excitation limit should be verified in the same way the under-excitation limit is verified.
Response: The GVSDT thanks you for your comment. Operation beyond the capability of the equipment is not expected nor required. The GVSDT believes that a stabilization period is needed to assure that verified data is sustainable. The GVSDT also believes that the rated power lagging test is the most demanding so that extended operation at other test points would not be required.		
Austin Energy	No	The ERCOT required verification time is 15 minutes. Extending the verification time to one hour is burdensome with unclear benefit.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Ingleside Cogeneration LP	No	Ingleside agrees in principle that one hour is sufficient at this test point, but believes it should take place at the limit identified in the Transmission Operator's reactive capability schedule.
Response: The GVSDT thanks you for your comment. The requirement is intended to verify the D-Curve of the generator for planning studies, not Real-time operations.		
American Electric Power	Yes	This requirement is stated in Attachment 1, section 2.3.
Response: The GVSDT thanks you for your comment.		
ISO New England	Yes	Yes, the standard should also require a recording of generator vibration during the test and require that the Generator Owner report an increase in vibration over the test period indicating the presence of rotor shorted turns that would limit long term generator MVAR loading. One hour may be enough time to determine if rotor shorted turns are present as indicated by vibration but the vibration must be recorded. The reactive power output data recording should be at 5 minute intervals and use the average for the hour. Also testing leading capability at minimum real power loading should be held for five minutes.
Response: The GVSDT thanks you for your comment. The GVSDT believes that a one-hour period is sufficient for most units to be stable, regardless		

Organization	Yes or No	Question 6 Comment
of the reason. Although vibration is a potential indicator of problems such as thermal stability in the field, if it can be held to operable levels for an hour that is sufficient for planning purposes. The GVSDT believes that data recorded at the end of the test is sufficient for planning purposes.		
BC Hydro	Yes	It may be better to specify a particular rate of change of measured temperature determining that heating has stabilized instead of selecting an arbitrary time period.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification. The reliability goal of the one hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
FirstEnergy	Yes	Although we are OK with the 1 hour interval, we are not convinced this will meet the reliability goals of the standard. Just being able to hit a specific reactive output is one thing, but that does not assure Reliability. Most large generators and large main transformers have only reached one, possibly two, thermal time constants within an hour timeframe There are many thermal problems that can be identified if the electrical equipment is permitted to be operated at high load levels over an extended period of time. It may be necessary to show that reactive output can be maintained over a longer period of time.
Response: The GVSDT thanks you for your comment. The overwhelming majority of stakeholders agree with the one-hour verification period. The reliability goal of the one-hour verification is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
Public Service Enterprise Group	Yes	The drafting team should provide the rationale for the one hour minimum for over-excited reactive capability.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that temperatures on the generator are relatively stable and the verification reflects a capability that is sustainable. The GVSDT believes that the majority of generators will be sufficiently stable after one hour to meet the reliability objective of the standard.		
SERC Generation sub-committee	Yes	Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data.		

Organization	Yes or No	Question 6 Comment
Southern Company	Yes	Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data. See response to Question 14.		
Associated Electric Cooperative, Inc.	Yes	Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method.
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data.		
Duke Energy	Yes	Provided that the verification is accomplished through staged testing or through operational data review and a unit is capable of reaching the expected over excited capability, 1 hour should be adequate to determine if equipment temps that might limit capability are stabilized. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Response: The GVSDT thanks you for your comment. The GVSDT believes this requirement would apply regardless of using a staged test or operational data. See response to Question 14.		
Exelon	Yes	The time of one hour as a minimum is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the generator reactive capability curve (RCC).
Response: The GVSDT thanks you for your comment. The standard has been revised to clarify that Real and Reactive Power testing may be done at different times (see Summary Response to question 1).		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization's	Yes	

Organization	Yes or No	Question 6 Comment
NERC Standards Review Forum (NSRF)		
Dominion	Yes	
SERC Dynamics Review Sub-committee	Yes	
Westar Energy	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Salt River Project	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	

Organization	Yes or No	Question 6 Comment
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Independent Electricity System Operator	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Wisconsin Public Service Corp		No Comment.
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)
Response: The GVSDT thanks you for your comment.		

7. Verification of (1) under-excited Reactive capability at rated Real Power of the most recent gross verified Real Power capability reported, (2) under-excited Reactive capability at expected minimum Real Power output and (3) over-excited Reactive capability at expected minimum Real Power output are all to be recorded as soon as a limit is encountered. Do you agree that such data recorded as soon as a limit is encountered is appropriate for such verification? If not, please explain.

Summary Consideration: The majority of stakeholders agree that the data should be recorded as soon as a limit is reached. A few stakeholders suggested that a holding or settling time be added to make certain that a limit was reached. Several stakeholders suggested that minimum Load testing, minimum Load over-excited testing or under-excited testing of nuclear units was not needed or desirable. The following statement was added to Note 1 of Attachment 1 for clarity:

> "Auxiliary bus voltage limits should be observed."

Organization	Yes or No	Question 7 Comment
Consolidated Edison Co. of NY, Inc.	No	We recommend allowing the Transmission Operator (TOP) flexibility in determine the specific detailed nature of the reactive power tests performed in support its modeling. Regarding Part 2.1, in the NYISO, the maximum reactive power is tested at a real power level above 90% of maximum real power capability. The test was designed in this manner for a two reasons: (1) not to be a simultaneous test with 100% real power test and (2) to provide a reliable maximum reactive power test when the unit is stressed, but is still capable of providing reserve power. We recommend providing the TOP flexibility in this requirement by allowing reactive power to be tested above 90% of maximum real power capability. The NYISO Ancillary Services Manual also contemplates that GO's will test lagging and leading reactive power during time periods more appropriate to their use. On p. 28 and p. 34 the manual states: o Lagging MVAr capability testing will normally be performed during on-peak hours. The VSS Supplier must operate at maximum Lagging MVAr for at least one hour for the test to be acceptable. o The Leading MVAr testing will normally be performed during off-peak hours. The Leading MVAr test shall be scheduled with the corresponding TO, who will inform the NYISO. Ref: http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf Presumably, under the NYISO tariff the leading and lagging Reactive Power tests would not be performed at

Organization	Yes or No	Question 7 Comment
		the same time or necessarily at the same "rated gross Real Power capability."ISO-NE also notes that maximum leading and lagging reactive power may not be at the same real power output level. o Points #4 and #9 in Figure #1, the two [lagging and leading] break points, do not necessarily correspond to the same MW output of the Generator. Ref: http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14b_rto_final.pdf Proposed language change to MOD-025 Attachment 1: 2.1. Perform verification of Real and Reactive Power capability of all generating units at maximum over-excited (lagging) and under-excited (leading) reactive capability at rated gross Real Power capability1, or at the Real Power level stipulated by the Transmission Operator. ...
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the language in the NYISO document, Table 3.1. The table uses terms UCAP and ICAP. The revised standard contains language in Item 2.1 of Attachment 1 that states the verification is to be performed at "the generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." A test to satisfy MOD-025 would appear to meet the requirements for the NYISO, while also meeting the statement, "Extreme measures that might overstate a unit's Reactive capability must be avoided," in Section 3.6.2 of the NYISO document.		
Northeast Power Coordinating Council	No	Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the language in the NYISO document, Table 3.1. The table uses terms UCAP and ICAP. The revised standard contains language in Item 2.1 of Attachment 1 that states the verification is to be performed at "the generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." A test to satisfy MOD-025 would appear to meet the requirements for the NYISO, while also meeting the statement, "Extreme measures that might overstate a unit's reactive capability must be avoided," in Section 3.6.2 of the NYISO document.		
Northeast Utilities	No	Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the language in the NYISO document, Table 3.1. The table uses terms UCAP and ICAP. The revised standard contains language in Item 2.1 of Attachment 1 that states the verification is to be performed at "the generating unit's normal (not emergency) expected maximum Real Power at the time of the verification." A test to satisfy MOD-025 would appear to meet the requirements for the NYISO, while also meeting the statement, "Extreme measures that might overstate a unit's reactive capability must be avoided," in Section 3.6.2 of the NYISO document.		
IRC Standards Review Committee (joint comments)	No	See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Response: The GVSDT thanks you for your comment. Please see response to question 2.		
SPP Reliability Standards Development Team	No	We would request that the time be a few minutes to make sure after a settling period that it was a limit that was encountered.
Response: The GVSDT thanks you for your comment. The GVSDT feels that the time needed to take data should be a sufficient settling period.		
Dominion	No	For items 2 and 3 see comments in question 5. We agree with item 1.
Response: The GVSDT thanks you for your comment. Please see response to question 5.		
Westar Energy	No	We suggest that the SDT considering adding clarifying language around "as soon as a limit is encountered." The current language is ambiguous.
Response: The GVSDT thanks you for your comment. The GVSDT believes the language is clear. We welcome suggested edits that you believe would provide the clarity that you seek.		
New York Independent System Operator	No	Testing requirements for reactive capability at minimum real power output should be removed. These tests are of no value and lead to system limit concerns. The testing requirement should be changed to two test points. One test for an hour to verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner. A second test to verify under-excited capability (leading)

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>at the real power level specified by the Transmission Operator or the Transmission Planner.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.</td></tr>
<tr><td>Cowlitz County PUD</td><td>No</td><td>Cowlitz at this time has insufficient information to formulate an opinion, but at the same time is skeptical of the reliability benefit being great enough to justify the cost of obtaining this data.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The data us being collected as a result of a FERC directive in paragraph 1321 which states:

“1321. We disagree with commenters that verifying generator Reactive capability is a particularly difficult issue. The capability of generators to produce Reactive Power is essential for Real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify Reactive capability only at the unit’s full MW Loading. However, other than base load units, most generating units rarely operate at full MW Loading. It is unclear what Reactive capability is available throughout a unit’s Real Power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit’s Real Power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit’s operating range.</td></tr>
<tr><td>Ameren</td><td>No</td><td>(1) From transmission perspective: If a plant limit is encountered in the testing, and it is a hard limit not to be exceeded, then the capability at this limit should be recorded. If a limit is identified on the transmission system such that the testing cannot be completed, then the capability should be noted but this would not be a firm limit.

(2) From GO perspective : Our testing people won't know if the transmission system is causing the limit because they aren't allowed to "see" the transmission system. Second, they are not allowed to test at time of seasonal peak because their testing may jeopardize the availability of the unit and testing during the fall and spring will mean higher voltages and frequently some type of testing limit is reached. Engineering calculations and justification should be allowed. Finally, we thought the 20% "margin" was to allow for these unavoidable risk restraints on testing the units. If a plant limit is encountered in the testing, then the capability at this limit should be recorded. However, it is unclear how this data, and the 20% margin, should be used in the verification process. We request the SDT clarify how data readings within the 20% margin should be used to determine the Real and Reactive capabilities of a generator or plant.</td></tr>
</table>

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comment. The GVSDT agrees that an entity should record data for a hard limit when the unit reaches the limit. While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling. Communication with the Transmission Operator is necessary when performing testing and system voltage limits would be part of that communication. The 20% margin was meant to be a permissive limit to accept operational data. The 20% value was removed and the wording of Item 2 in Attachment 1 has been modified in the standard based on industry feedback. 2. Perform verification with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification, and the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification, as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50% of the capability shown on the appropriate D-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations(for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:		
Indeck Energy Services	No	Only if they are required for particular units.
Response: The GVSDT thanks you for your comment. The test points are required for all applicable units.		
Ingleside Cogeneration LP	No	Ingleside agrees in principle that a demonstration that the generator can reach these test points is sufficient, and reduces the risk to the equipment. However, the limits identified in the Transmission Operator's reactive capability schedule should be verified, not the generator's operational limits.
Response: The GVSDT thanks you for your comment. The intent of MOD-025 is to verify generator capability for long-term planning studies. Real-time issues with a Transmission Operators voltage schedule are not included in this standard.		
ISO New England	No	These types of tests should require remaining at the point for a length of time. Under-excited power verification at minimum power output for five minutes should be adequate. Testing requirements for over-excited reactive capability at minimum real power output and under-excited capability at maximum power should be removed. These tests lead to transmission system voltage concerns.
Response: The GVSDT thanks you for your comment. The GVSDT believes that the time required to take the data is sufficient for under-excited tests.		

Organization	Yes or No	Question 7 Comment
The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Communication with the Transmission Operator is necessary when performing testing and system voltage limits would be part of that communication.		
Public Service Enterprise Group	Yes	This documents the system conditions and unit conditions when limits are reached.
Response: The GVSDT thanks you for your comment.		
Great River Energy		GRE would object to doing this at URGE because URGE is not our normal operating condition. The reactive power testing should be done at normal full load (normal operating conditions) to be representative of how much reactive power the unit can put out or absorb during normal running conditions. GRE doesn't agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
GenOn Energy	Yes	The intent of the question is not well understood. The answer is complicated by the inability to replicate the system condition that will demand the unit operating limits, creating artificial lower limits under the test conditions.
Response: The GVSDT thanks you for your comment.		
SERC Generation sub-committee	Yes	But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit below (attempted to include graphic).
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission		

Organization	Yes or No	Question 7 Comment
Planner can use for modeling.		
Tennessee Valley Authority GO	Yes	But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Southern Company	Yes	We believe that the minimum load, it will be difficult for a unit to produce Vars because the system usually has minimum VAR output requirements from generators when the generators are operating at minimum load. Therefore, we believe verification of Vars out at minimum load will not provide the data that transmission planning is seeking and, therefore, this requirement is not necessary. See our response to Question 5 for additional discussion on verification at minimum load.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Associated Electric Cooperative, Inc.	Yes	We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR requirements when operating at low system load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission		

Organization	Yes or No	Question 7 Comment
Planner can use for modeling.		
Duke Energy	Yes	We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit (Graphic has been provided to the SDT). There needs to be standards on how model values are selected, such as, o The lagging capabilitiy values should be based on 90% of gross generator capability at minimum normal Hydrogen pressure minus aux system loads and xfmr losses o The leading capability values being modeled should be based on (UEL limiter setpoints as documented by PRC-19 coordination is probably appropriate).
Response: The GVSDT thanks you for your comment. The FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve. Also, while not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltage than encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of unit capability that the Transmission Planner can use for modeling.		
Exelon	Yes	Recording the test data as soon as a limit is encountered is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the reactive limits given by the plant specific generator reactive capability curve (RCC) at the attainable real power output. Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Suggest the following revision to Attachment 1 as follows:2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comment. Language has been added to make it clear that Real and Reactive Power tests are not required to be performed at the same time. The GVSDT feels that if a nuclear plant has under-excited capability it should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, "Auxiliary bus voltage limits should be observed."		
Luminant Power	Yes	See Luminant comments to Question #5 regarding operating ranges for testing.
Response: The GVSDT thanks you for your comment. Please see response to question 5.		
BC Hydro	Yes	Only verification of (1) has practical significance; (2) and (3) are redundant. Please see Comment 5.
Response: The GVSDT thanks you for your comment. Please see response to question 5.		
American Electric Power	Yes	This is stated in Attachment 1, section 2.4. A clarification could be in order to relate the recording of the time when the limit is reached to the requirement that the test be conducted over a one hour interval. For example, if a limit is reached in 15 minutes, is the verification test completed or is the expectation that the unit is held at that level for the balance of the one hour test window. Also, it is curious why this question excludes the condition of over-excited reactive capability at the rated gross real power per Attachment 1, section 2.1.
Response: The GVSDT thanks you for your comment. The intent, as stated, is that the Reactive Power lagging test at rated Real Power and the Real Power test be held for one hour; once that level is attained, to allow the unit to stabilize before taking data. All other reactive power tests need only be held long enough to take data.		
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Idaho Power-Power Production	Yes	
PPL Generation	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 7 Comment
SERC Dynamics Review Sub-committee	Yes	
NERC Staff	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
Dynegy Inc.	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Constellation Power Generation	Yes	
Wisconsin Public Service Corp	Yes	

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Yes	
CPS Energy	Yes	
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Chelan County PUD	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

8. Synchronous condensers are also reactive resources that may be important to reliability, but they are not generators. The SDT proposes that synchronous condensers be verified under MOD-025-2. Do you feel that this is appropriate?

Summary Consideration: There was overwhelming stakeholder support for verifying synchronous condensers as a Reactive resource under MOD-025-2. Some stakeholders suggested that consideration be given under this or a different standard for verification of other Reactive resources.

The SDT added the following sentence to the first paragraph of Attachment 1 in response to a stakeholder comment: "If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."

Organization	Yes or No	Question 8 Comment
Ingleside Cogeneration LP	No	There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.
Response: The GVSDT thanks you for your comment. The GVSDT has sufficient expertise to recommend synchronous condensers be included under the verification requirements of MOD-025 to help ensure the reliability of the BES.		
Indeck Energy Services	No	They are owned and registered differently.
Response: The GVSDT thanks you for your comment. Synchronous condensers are not currently included in the compliance registry. The GVSDT has sufficient expertise to recommend synchronous condensers be included under the verification requirements of MOD-025 and, hence, the compliance registry, to help ensure the reliability of the BES.		
Oncor Electric Delivery Company LLC	No	Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard
Response: The GVSDT thanks you for your comment. The GVSDT disagrees and has included Reactive verification for synchronous condensers.		
Southern Company	No	

Organization	Yes or No	Question 8 Comment
Imperial Irrigation District (IID)	Yes	THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Response: The GVSDT thanks you for your comment.		
Pepco Holdings Inc Affiliates	Yes	However, based on the requirements and measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only apply to Transmission Owners that own synchronous condensers. If that is the case, Section A- 4.1.2 should be re-written as follows: "Transmission Owner that owns a synchronous condenser." This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined.
Response: The GVSDT thanks you for your comment. The standard applies to TOs that may own synchronous condensers, and this is reflected in Section 4.1.2, as suggested..		
FirstEnergy	Yes	Yes, we believe they should be verified because they are the same type of dynamic, voltage independent, source of reactive power as is a real power generator. We also believe that they certainly are generators, generators of reactive power. In fact, they are identical in function, design and equipment as a real power generator, minus the prime mover. A synchronous condenser, like its sister the real power generator, can be continuously adjusted for the desired output and contains equipment that must be properly adjusted to provide the desired range of reactive output.
Response: The GVSDT thanks you for your comment. The GVSDT concurs with your comments.		
SERC Dynamics Review Sub-committee	Yes	Synchronous condensers supply reactive power to the grid. Therefore, the Transmission Planner needs to know a verified capability for the device.
Response: The GVSDT thanks you for your comment.		
NERC Staff	Yes	Although the penetration of synchronous condensers in North America is low, in most cases they are applied to address a reliability need, making it necessary to have accurate models of these devices for system studies. Although other devices may be outside the scope of this standard, accurate models are similarly necessary for devices such as static var compensators (SVCs) and static compensators (STATCOMs).
Response: The GVSDT thanks you for your comment. Synchronous condensers are synchronous machines, so the GVSDT feels they should be included with other synchronous machines. Solid state devices are significantly different, and the GVSDT believes that a separate SAR should be		

Organization	Yes or No	Question 8 Comment
drafted to cover these devices.		
Manitoba Hydro	Yes	To cover all configurations, the standard should also include and stipulate that synchronous machines that operate as generators at some times and as synchronous condensers at other times must perform a reactive capability test in each operating mode. This may be covered in Applicability 4.2.1 however the current wording should be modified to make this clear.
Response: The GVSDT thanks you for your comment. The following sentence was added to the beginning of Attachment 1: **"If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."**		
Independent Electricity System Operator	Yes	The standard should also be applicable to static var compensators and similar equipment used in reliability assessments of the BES.
Response: The GVSDT thanks you for your comment. Synchronous condensers are synchronous machines so the GVSDT feels they should be included with other synchronous machines. Solid state devices are significantly different, and the GVSDT believes that a separate SAR should be drafted to cover these devices.		
ISO New England	Yes	Yes, but as written the standard is not clear as to how the testing is to be performed for a synchronous condenser.
Response: The GVSDT thanks you for your comment. The following was added to the beginning of Attachment 1: **"For synchronous condensers, the verification should be performed as specified below with the exception of the Real Power Capability testing."**		
Cowlitz County PUD		Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
IRC Standards Review	Yes	

Organization	Yes or No	Question 8 Comment
Committee (joint comments)		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee	Yes	
Idaho Power-Power Production	Yes	
PPL Generation	Yes	
Dominion	Yes	
Public Service Enterprise Group	Yes	
ACES Power Members	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
Associated Electric Cooperative, Inc.	Yes	

Organization	Yes or No	Question 8 Comment
New York Independent System Operator	Yes	
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Electric Power	Yes	
Wisconsin Public Service Corp	Yes	

Organization	Yes or No	Question 8 Comment
GenOn Energy	Yes	
Duke Energy	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indiana Municipal Power Agency	Yes	
Tacoma Power		None
SERC Generation sub-committee		No GS comment
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

9. The SDT proposes that the size of synchronous condensers to be verified be limited to those greater than 50 MVA. Do you feel that this size criterion for synchronous condenser verification is appropriate?

Summary Consideration: There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. While some commenters suggested values higher than 20 MVA, technical justification was not provided for a value exceeding the generator registration criterion of 20 MVA.

Organization	Yes or No	Question 9 Comment
IRC Standards Review Committee (joint comments)	No	There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Dominion	No	First, we would like to state that we did not see the 50 MVA threshold in the posted version of this standard. And, if we had, we would not have agreed. If 20 MVA is the appropriate threshold for a generator, it is appropriate for a synchronous condenser.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SERC Planning Standards Subcommittee	No	We recommend a limit of 20 MVA since these may be in remote areas where reactive capability is critical.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		

Organization	Yes or No	Question 9 Comment
Southern Company	No	This MVA size does not agree with that found in the Applicability section 4.2.1 (20 MVA). As previously stated, we feel that the size of an individual unit that is significant in the Eastern Interconnection is 100 MVA.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Tennessee Valley Authority GO	No	It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SERC Dynamics Review Sub-committee	No	A 50 MVA criteria for synchronous condensers is not in the standard. The standard says 20 MVA. However, a criteria of 75 MVA would be a more reasonable number. Units smaller than 75 MVA will have little impact to the reliability of the grid.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
NERC Staff	No	Section 4.2.1 indicates the standard is applicable to synchronous condensers greater than 20 MVA. We agree that the standard should be applicable to synchronous condensers greater than 20 MVA rather than 50 MVA.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SERC Generation sub-committee	No	It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Associated Electric Cooperative, Inc.	No	It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		

Organization	Yes or No	Question 9 Comment
New York Independent System Operator	No	100 MVA is a more appropriate limit.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Independent Electricity System Operator	No	There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Ameren	No	The size of synchronous condensers to be verified should be consistent with generator sizes which need to be verified. Testing for units less than 75 MVA should not be required.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Oncor Electric Delivery Company LLC	No	Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard therefore we believe this criterion is not applicable to this standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. Reactive output of synchronous condensers directly impacts the reliability of the BES.		
Georgia Transmission Corporation	No	20 MVA seems more consistent with the reasoning in question 4.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Ingleside Cogeneration LP	No	There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.

Organization	Yes or No	Question 9 Comment
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Wisconsin Public Service Corp	No	Synchronous condensers are specifically for local area voltage regulation purposes. Units between the sizes of 20MVA to 50MVA could be significant to an area's dynamic performance under contingencies.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
ISO New England	No	There is no technical justification supporting the 50 MVA criterion. Absent this, we propose to use the Compliance Registry criteria for generators of 20 MVA as a general criterion for data being verified for synchronous condensers over 20 MVA as well.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Manitoba Hydro	No	The 50MVA criteria in question 9 does not appear in the draft standard (only in the implementation plan). If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Indeck Energy Services	No	
Public Service Enterprise Group		A 50 MVA minimum size for synchronous condensers was not found in the proposed standard - see paragraph 4.2.1 which has a 20 MVA minimum. Whether the limit was intended to be 50 MVA or the 20 MVA limit stated in the draft, the SDT should provide a justification of basis for that MVA threshold. The impact that such smaller units would have on the BES is not substantial enough to justify requiring their inclusion in this standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included		

Organization	Yes or No	Question 9 Comment
a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Cowlitz County PUD		Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Response: The GVSDT thanks you for your comment.		
BC Hydro		Not clear why would verification be required for generating units over 20 MVA while for SCs the threshold is over 50 MVA, especially having in mind that SCs are specifically used to provide reactive support
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Xcel Energy	Yes	There is a discrepancy between this question and the size limit in the draft standard (20 MVA). We believe 50 MVA is the better value.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Westar Energy	Yes	We agree with the 50 MVA limit, however the standard does not currently address this limit.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Imperial Irrigation District (IID)	Yes	THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Response: The GVSDT thanks you for your comment.		
Pepco Holdings Inc Affiliates	Yes	Question 9 mentions that a threshold was proposed by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included		

Organization	Yes or No	Question 9 Comment
a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
SPP Reliability Standards Development Team	Yes	We agree with the 50 MVA limit but would request that it be included in the actual standard.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
FirstEnergy	Yes	The applicability section does not mention the 50 MVA threshold.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
American Electric Power	Yes	The current draft of the standard in section 4.2.1 proposes that the size of synchronous condensers to be verified be limited to those greater than 20 MVA, not 50MVA as stated in this question. Regardless, either limit would be acceptable.
Response: The GVSDT thanks you for your comment. There was an error in the comment form for this question. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Northeast Power Coordinating Council	Yes	
PPL Generation	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 9 Comment
South Carolina Electric and Gas	Yes	
Tri-State Generation and Transmission, In.	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Gainesville Regional Utilities	Yes	
APS		being intentionally left blank (no answer to be provided)
Tacoma Power		None
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.

10. Either operational data or staged testing is allowed by the standard for verification. Do you agree that these two methods of verification are acceptable? If not, please explain.

Summary Consideration: Most stakeholders agree that either operational data or staged testing should be allowed for verification.

Organization	Yes or No	Question 10 Comment
SERC Generation sub-committee	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." The SERC GS could provide a template for this. Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in Attachment 1 states:**		

Organization	Yes or No	Question 10 Comment
Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling." TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).		
Southern Company	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). Reliance on data from testing or operations alone will result in understated reactive capabilities for planning purposes. To provide these alternative methods of establishing P&Q capabilities for each applicable facility, it is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or Attachment 3 (by engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."**		

Organization	Yes or No	Question 10 Comment
TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).		
Tennessee Valley Authority GO	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."** **TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).**		
Associated Electric Cooperative, Inc.	No	As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify more appropriate generating unit reactive capabilities that are needed to ensure that planning entities have accurate generator data when assessing BES reliability. MOD-025-2 should not focus solely upon operational testing to

Organization	Yes or No	Question 10 Comment
		determine capabilities used for planning models, because experience has shown that testing does not provide appropriate reactive power capabilities. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."** **TOP-002-2a, R13 is proposed for retirement by the RTOSDT (Project 2007-03).**		
Duke Energy	No	As the draft is currently written, these two methods are understood to be allowed, but experience has shown may not be able to fully validate the available capabilities. We believe engineering analysis could be used in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. The answer may be to test or operate as far as you can based on system voltage and then evaluate margin to unit thermal limits (Generator, Bus, GSUs, etc) and determine if you could reasonably have reached full capability if system conditions warranted the need.
Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve."** **And Note 2 in attachment 1 states:** **Note 2: "While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 10 Comment</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td>Ameren</td><td>No</td><td>While these two methods are acceptable, there is not enough flexibility included to allow for engineering support if necessary.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states:

“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve.”

And Note 2 in attachment 1 states:

Note 2: “While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.”</td></tr>
<tr><td>Indeck Energy Services</td><td>No</td><td>Engineering analysis should also be available</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. It is envisioned that engineering analysis may be used to supplement operational data or staged testing. The GVSDT does not believe that engineering analysis alone is sufficient. Attachment 1, Section 2 of the proposed standard states:

“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve.”

And Note 2 in attachment 1 states:

Note 2: “While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.”</td></tr>
<tr><td>Pepco Holdings Inc Affiliates</td><td>Yes</td><td>“Staged” vs “operational” verification should be defined. In Attachment 1, are sections 2 and 5.2 consistent? That is should the % value be the same?</td></tr>
</table>

Organization	Yes or No	Question 10 Comment
Response: The GVSDT thanks you for your comment. A staged test is simply one that is scheduled for purposes of verification whereas an operational verification includes historical performance records. Section 2 was revised to, "At least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-Curve". This makes Section 2 and 5.2 consistent. The percentage in Section 2 refers to the data that is acceptable to be used for verification for operational data where the percentage in 5.2 is the criterion for the level of change in a Facility capability that triggers the need to perform another verification. The GVSDT felt that the percentages chosen were appropriate for the intended purpose. The wording in Section 2 was revised to clarify intent.		
Cowlitz County PUD	Yes	Operational data will always be the preferred method of obtaining verification; however Cowlitz can't see how this would be possible for obtaining the reactive capabilities as prescribed. This will require costly and burdensome staged testing.
Response: The GVSDT thanks you for your comment. In order to obtain the data required by the standard, staged testing may be required. It is believed that staged testing can be scheduled at the required Load levels along with other plant operations (e.g. startup/shutdown, high Load, etc.) and since verification is required only once every five years (in most cases), the effort is not considered to be costly or burdensome.		
Ingleside Cogeneration LP	Yes	There is no reason to preclude the use of actual operations data in validation exercises.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	

Organization	Yes or No	Question 10 Comment
SERC Planning Standards Subcommittee	Yes	
Idaho Power-Power Production	Yes	
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee	Yes	
NERC Staff	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Public Service Enterprise Group	Yes	
Luminant Power	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
Dynegy Inc.	Yes	
New York Independent System	Yes	

Organization	Yes or No	Question 10 Comment
Operator		
Tri-State Generation and Transmission, In.	Yes	
Xcel Energy	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy	Yes	
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Electric Power	Yes	
Wisconsin Public Service Corp	Yes	

Organization	Yes or No	Question 10 Comment
ISO New England	Yes	
Lincoln Electric System		
CPS Energy	Yes	
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Chelan County PUD	Yes	
APS		being intentionally left blank (no answer to be provided)
Tacoma Power	Yes	None
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Manitoba Hydro	Yes	

11. If operational data is utilized, the standard requires the verification be within 20 percent of the expected value. Do you agree with the 20 percent requirement? If not, please explain.

Summary Consideration: Many of the comments indicated that the proposed language in the standard on this point was confusing so the GVSDT has revised the language to better clarify intent. Several commenters indicated the 20percent tolerance value was too high, while others thought this value was too restrictive. The revised wording specifies the percentage selection criterion is applied to "the last reported capability." Attachment 1, Item 2 was revised to include:

Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50percent of the capability shown on the associated D-Curve.

The GVSDT believes this change will alleviate commenter concerns. The GVSDT disagrees with commenters suggesting operational data restrictions should not be included.

Organization	Yes or No	Question 11 Comment
IRC Standards Review Committee (joint comments)	No	We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: "Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" We interpret that the "IT" refers to the operational data. As such, we do not understand the "within 20% of the expected value". Does it mean the generator's real power output during the period from which operational data was collected must be within 20% of the generators' declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity. As written, we are unable to comment on the acceptability of the 20%.

Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state:

"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out

Organization	Yes or No	Question 11 Comment
of service), then the next verification shall be by another staged test, not operational data.” **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Pepco Holdings Inc Affiliates	No	20% “appears” to be a large variance. The DT should explain the justification for 20%. 5% or 10% would seem more reasonable, especially for large units.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data.”** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
SPP Reliability Standards Development Team	No	We feel that 20% is too great a buffer for this data and would suggest that the number reflect a buffer of 10% or less. We feel like having a buffer that is too high would cause entities to not use testing verification and would use the operational data verification. We also feel that this verification should be as accurate as possible to reflect the system in planning.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data.”** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
SERC Planning Standards Subcommittee	No	The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate

Organization	Yes or No	Question 11 Comment
		expected limit.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Idaho Power-Power Production	No	What is the technical basis for the 20%? It seems high.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Santee Cooper	No	First of all "expected value" is not defined. Second any expected value based solely on nameplate data is subject to great variation based on the system the generator is connected to and should not be used to draw conclusions of satisfactory or unsatisfactory test results.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last**		

Organization	Yes or No	Question 11 Comment
reported verified capability. The phrase, "expected value" is not used in the revised standard.		
PPL Generation	Yes	Note however that the expectation, as discussed above, is (for certain PPL Generation Registered Entities' units) derived from the aux bus limits, not the D-curve.
Response: The GVSDT thanks you for your comment.		
Dominion	No	If the question was meant to ask whether we agree with the sentence that reads" Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" (Attachment 1, @2) then we respond affirmatively. However, we do not agree that a verification MUST be within 20%. It is possible that a physical change to either the asset being verified or the system it is interconnected with may result in its inability to perform to within 20%. If this is true, then we could agree that any such variance must be accompanied by an explanation as to why the verification did not fall with the 20% 'boundary'. There should be no requirement for percent of expected value.
Response: The GVSDT thanks you for your comment. You are correct with regard to the intent of the sentence. The intent of this standard is to verify the capability of a generator or synchronous condenser. A staged verification or operational data may be used for the verifications required by MOD-025. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **If a physical change occurs to an asset the verification should be based on the assets demonstrated capability with that change accounted for.**		
FirstEnergy	No	If the generating unit is capable of reaching 20% of the "expected value", than why should verification be concluded at that point? (We could potentially be missing out on fully realizing the potential of a reactive resource by pre-maturely ending the verification. A very important dimension of this verification (that was touched on in the Standard) is the recognition of equipment conditions or voltage regulator settings that could be improved when a staged test is performed. It is difficult if not impossible to capture equipment shortcomings or limitations which can be very useful to improving operations when verifying through the use of Operational data. Also, we need clarification regarding what would be considered "within 20% of expected value" if your leading reactive limit was 0 MVAR (unity)?
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to		

Organization	Yes or No	Question 11 Comment
state: **“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90% of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data.”** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. This change is not intended to limit the scope of effort performed during a staged test. This change only establishes acceptance criteria for using operational data for verification in lieu of performing a staged test.**		
SERC Dynamics Review Sub-committee	No	The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data.”** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The intent of this statement is to allow an entity to use operational data in lieu of performing a staged test if the operational data is at least 90percent of the last reported verified capability.**		
NERC Staff	No	We agree the standard should provide flexibility to the Generator Owner; however, the need for flexibility must be balanced against the need for valid models for system studies. Accuracy must be at least as stringent as required for market dispatch. When operational data cannot be verified within 5% of the expected value, an entity should be required to provide data based on staged testing.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-**		

Organization	Yes or No	Question 11 Comment
Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The operational data would always have been preceded by a staged test to demonstrate the unit/Facility capability. The allowance for operational data that is at least 90percent of a prior staged test with reasonable results will allow for a reduced burden on the GO or TO. The GVSDT disagrees that verification within 5percent of an expected value should require staged testing in this case because the expected value is mostly dependent on the system conditions at the time of the test rather than the unit's/facilities capabilities. If the unit/Facility cannot reach the revised criteria mentioned above, another staged test would then be required.**		
Public Service Enterprise Group	No	Attachment 1 is unclear as to the implementation of the 20% requirement. Paragraph 2 states "Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" As written, it appears that the 20% only applies to operational data "within the year prior to the verification date." Does the 20% apply also to staged tests? If not, why not? Paragraph 5.2 in Attachment 1, regarding operational tests, is also relevant: "If data for different points is recorded on different days, the Generator Owner shall designate one of the dates as the verification date, and report that date as the verification date on MOD-025- Attachment 2 for periodicity purposes." Is the SDT proposing to comingle operational data from one-year prior to the verification date as long as it is within 20% of the expected value? If so, what value would be reported - the test data that may be up to 20% higher or lower than the expected value or the expected value?
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
SERC Generation sub-committee	No	Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D-curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in

Organization	Yes or No	Question 11 Comment
		normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their under excitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference comment 2 under Question 14 for additional discussion on the verification methods.Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. **Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state:** **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Arizona Public Service Company	No	If by expected, it means maximum/minimum, then no. In many operating conditions, one does not get within 20% of the maximum/minimum. Need to be clear about what expected means.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		

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<tr><td>Southern Company</td><td>No</td><td>The "expected value" is not clearly identified, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the D curve for lagging Vars, we believe this is not a realistic expectation because operational data for most generating units does not approach 80% of the D curve value in normal operating conditions or even in staged testing based on our experience. A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed to be an alternative method for verifying the unit capability, the 20% tolerance given above is not needed. See our Comment 2 under Question 14 for additional discussion on the verification methods.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The phrase, “expected value” is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state:

“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data.”

The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.</td></tr>
<tr><td>Tennessee Valley Authority GO</td><td>No</td><td>Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed.Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not</td></tr>
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<tr><td></td><td></td><td>give the appropriate expected limit.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The phrase, “expected value” is not used in the revised standard. Based on comments and further review the GVSDT has revised the sentence in Section 2 to state:
“Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data.”
The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.</td></tr>
<tr><td>South Carolina Electric and Gas</td><td>No</td><td>The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT does not agree that “any” operational data is appropriate to be used as the basis for engineering analysis.</td></tr>
<tr><td>Associated Electric Cooperative, Inc.</td><td>No</td><td>Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed.</td></tr>
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</table>

Organization	Yes or No	Question 11 Comment
The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.		
New York Independent System Operator	No	What determines the expected value to be within 20% of?
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
Ameren	No	While the 20% margin is appropriate and appreciated, it is unclear if verifying the output of a generator at 80% of real rated output will satisfy regulator rating requirements at the time of seasonal peak. Thus, from the user of this data (e.g. planners), this % is too great. From the generator owner and testing personnel , this % makes sense and seems appropriate. We would suggest the SDT provide basis for this % and a guidance how it should be used for all conditions.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The GVSDT has added a note to Attachment 1 to allow for and encourage engineering analysis to provide a more reasonable estimate of unit capabilities in cases where system conditions will not allow the unit to demonstrate its full capability. The GVSDT does not believe that engineering analysis alone is sufficient and therefore testing is still required to show that limitations do not exist that would not be identified with engineering analysis such as a thermally sensitive field or an inaccurate limiter in the voltage regulator.** **Note 2: While not required by the standard, it is desirable to perform engineering analysis to determine expected applicable Facility capabilities**		

Organization	Yes or No	Question 11 Comment
under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.		
Indeck Energy Services	No	The point is that the rating should be changed to the value tested. If a unit can't reach it, it's not a rating.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The proposed standard allows engineering analysis to obtain the best possible results for use in modeling.**		
Oncor Electric Delivery Company LLC	No	Any operational varation from expected should be explained by the Generator Owner and a solution to provide full capability be presented.
Response: The GVSDT thanks you for your comment. This change only establishes acceptance criteria for using operational data for verification in lieu of performing a staged test. The reason for the variation must be included in the remarks section of Attachment #2 if a limitation is reached during verification testing.		
Georgia Transmission Corporation	No	The data should be accepted as is unless the data is meaningless.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		

Organization	Yes or No	Question 11 Comment
Austin Energy	No	This requires a guarantee to an expected performance that may be impacted by a particular operational problem during the test (high cooling water or ambient temperatures, etc). The test results should be accepted as is and logged as the new generator capability until such time as it is retested later with better results.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The reason for a variation must be included in the remarks section of Attachment #2 if a limitation is reached during verification testing.**		
BC Hydro	No	Such a wide margin seems to defeat the purpose of verifications. If such margin is technically acceptable to planners, the question is why even requiring verifications, especially for smaller units. It is hard to immagine that actual capability (active or reactive) of generating units/facilities would ever be lower than 80% of declared.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability.**		
American Electric Power	No	System conditions greatly affect the expected reactive power values as stated in Attachment 1, Notes 1 and 2. While 20% appears reasonable for the real power verification, there needs to be flexibility as to this value for reactive power, given that system conditions are not constant.

Organization	Yes or No	Question 11 Comment
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. Please note this statement specifies the acceptance criteria required for performing verification using operational data. If acceptable operational data cannot be obtained, then staged testing is required.**		
Ingleside Cogeneration LP	No	The real and reactive capacities should be validated to be within 20% of expectation at the limits identified in the Transmission Operator's reactive capability schedule, not the generator's operational limits.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The SDT disagrees that the verification should be against the TOP's reactive capability schedule since the data collected is for use in long-term planning studies, not for Real-time operations.**		
ISO New England	No	As we interpret the language, we do not agree with the 20% requirement. In the assessments performed in our area our goal is to use data that is much more accurate than what appears to be required under the standard. Allowing verification to be up to 20% inaccurate may result in inaccurate system assessments, potentially leading to overlooking potential system problems or to unnecessary system investment to address system concerns which are not really present. This value should be changed to a maximum of 5%.
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-**		

Organization	Yes or No	Question 11 Comment
Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The operational data would always have been preceded by a staged test to demonstrate the unit/Facility capability. The allowance for operational data that is at least 90percent of a prior staged test with reasonable results will allow for a reduced burden on the GO or TO. The GVSDT disagrees that verification within 5percent of an expected value should require staged testing in this case because the expected value is mostly dependent on the system conditions at the time of the test, rather than the unit's/Facilities capabilities. If the unit/Facility cannot reach the revised criteria mentioned above, another staged test would then be required.**		
Duke Energy	No	We have model validation requirements but no definitions to what we are needing to validate to. The "expected value" is not clearly defined, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference our response to Question #10.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. Please note this statement specifies operational data acceptance criterion and does not apply to staged testing.**		
Lincoln Electric System	No	The definition of "expected value" needs to be more clearly defined as it is somewhat unclear. The verification should probably be within at least 5percent of the expected output of the generating unit for a given ambient temperature, rather than 20% as stated in this draft. For a simple-cycle gas turbine the real

Organization	Yes or No	Question 11 Comment
		power output for the verification test would in most cases be greater than what it would be for summer peak conditions due to the higher generator output that typically occurs with these units as the turbine inlet temperature decreases. It is usually desirable to test the unit with the same conditions that the unit will be most needed. For summer peaking utilities this would be with reasonably high ambient conditions. When only recording real power data it is usually not that difficult to recordthe data in the summer when the units are already operating to serve the load. The coordination to record reactive power data at this time may be more difficult.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The proposed standard allows the use of operational data as an option when verifying units. If acceptable operational data cannot be obtained, then staged testing is required.**		
Independent Electricity System Operator	No	We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: "Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:"We interpret that the "IT" refers to the operational data. As such, we do not understand the "within 20% of the expected value". Does it mean the generator's real power output during the period from which operational data was collected must be within 20% of the generator's declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity.As written, we are unable to comment on the acceptability of the 20%.
Response: The GVSDT thanks you for your comment. The phrase, "expected value" is not used in the revised standard. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last**		

Organization	Yes or No	Question 11 Comment
reported verified capability.		
percentpercentpercent		
Chelan County PUD		For hydro, 20% of min and max reactive may be difficult to achieve. Salient pole machines have much greater lattitude than thermal, but system and bus conditions dictate if it is possible. Allowance should be made for realities in these cases. Again, what will dictate - voltage schedule or testing requirements?
Response: The GVSDT thanks you for your comment. Based on comments and further review, the GVSDT has revised the sentence in Section 2 to state: **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **The intent of this statement is that an entity may use operational data in lieu of a staged test if the operational data is at least 90percent of the last reported verified capability. The reason for the variation must be included in the remarks section of Attachment #2 if a limitation is reached during verification testing.**		
Westar Energy	Yes	
Luminant Power	Yes	
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 11 Comment
PacifiCorp	Yes	
Dynegy Inc.	Yes	
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Wisconsin Electric	Yes	
Great River Energy	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Manitoba Hydro	Yes	
Gainesville Regional Utilities	Yes	What is defined as the "expected value?"

Organization	Yes or No	Question 11 Comment
Indiana Municipal Power Agency	Yes	
Wisconsin Public Service Corp		No comment.
APS		being intentionally left blank (no answer to be provided)
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Response: The GVSDT thanks you for your comment.		

12. Are you aware of any regional variances that would be required for this standard?

Summary Consideration: Commenters have identified regional variances currently in effect, as required by MOD-024 and MOD-025. It is anticipated that these regional standards will be retired once MOD-025-2 is approved. Language provided by Relaibility*First* staff has been added to the Implementation plan concerning the Reliability*First* standards:

"It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements."

Organization	Yes or No	Question 12 Comment
SPP Reliability Standards Development Team	Yes	If the testing time is 1 hour as written then we have a variance of the SPP criteria of 15 minutes, but if the team decides to change that time limit then we wouldn't and our answer would change to no.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that generator temperature is stable and the verification demonstrates a sustainable capability. The GVSDT believes one hour is sufficient for the generator to reach thermal stability during testing for confirming the reliability objective of this standard. If MOD-025-2 is approved as proposed, then the SPP regional criteria will need to be revised. The continent-wide standard takes precedence over regional criteria. When this standard is approved, members of SPP will need to comply with the continent-wide standard. SPP could request a regional variance if SPP has technical justification to support the need for a 15-minute test period that is based on a physical difference in the bulk power system.		
Westar Energy	Yes	The SPP Criteria requires that the testing period should be 15 minutes rather than the 1 hour listed in the standard.
Response: The GVSDT thanks you for your comment. The reliability goal of the one-hour verification period is to ensure that generator temperature is stable and the verification demonstrates a sustainable capability. The GVSDT believes one hour is sufficient for the generator to reach thermal stability during testing for confirming the reliability objective of this standard. If MOD-025-2 is approved as proposed, then the SPP regional standard will need to be revised. The continent-wide standard takes precedence over regional criteria. When this standard is approved, members of SPP will need to comply with the continent-wide standard. SPP could request a regional variance if SPP has technical justification to support the need for a 15-minute test period that is based on a physical difference in the bulk power system.		

Organization	Yes or No	Question 12 Comment
Indeck Energy Services	Yes	The temperature adjustment probably varies by region. There is no basis in the ROP for members on one region to vote on requirements for another region. There are nationwide standards or regional standards. The SDT can't have it both ways.
Response: The GVSDT thanks you for your comment. Within a continent-wide standard, a requirement can include alternative performance based on different Facility characteristics, different regions, or different interconnections. (See INT-006-3 for an example.)		
Oncor Electric Delivery Company LLC	Yes	Oncor also recommends that consideration be given to a regional variance in that the information required of the Generator Owner as specified in R1 should be provided to the Planning Authority in the ERCOT region and not the Transmission Planner. This would align with current protocols, operating guide and planning guide as it relates to resource testing.
Response: The GVSDT thanks you for your comment. Oncor could sponsor a regional variance if its Region has technical justification to support the need for a variance based on a physical difference in the BES.		
Exelon	Yes	It is strongly suggested that the SDT review each existing Generator Real and Reactive Power Capability Regional Standard (or other guidance) currently in place for best practices and potential conflicts. As stated in responses to questions 5, 7, 13, and 14 nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Exelon Nuclear is a member of and has 17 nuclear units in two Regions (ReliabilityFirst and SERC). RFC Regional Standard MOD-025-RFC-01, "Verification and Data Reporting of Generator Gross and Net Reactive Power Capability," currently has a specific exclusion that "Under-excited (leading) Reactive Power capability verification is not required of nuclear units." SERC Regional Criteria, "Verification of Generator Real and Reactive Power Capability," has the following statement regarding nuclear units, " (t)he capabilities of nuclear units will be determined taking into consideration the fuel management program of the unit and any restrictions imposed by regulatory agencies.
Response: The GVSDT thanks you for your comment. RFC has informed the GVSDT that: **It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards once the NERC Board of Trustees approves the NERC MOD-025-2 standard. The purpose of this review is to ensure redundant and less restrictive requirements are either revised or considered for retirement from the RFC standards in accordance with the Reliability*First* Reliability Standards Development Procedure.** **Nuclear units are not required to perform Reactive Power verification at minimum Real Power output.**		

Organization	Yes or No	Question 12 Comment
Ingleside Cogeneration LP	Yes	TRE, WECC, and SERC have similar but slightly different requirements. It is Ingleside's expectation that these regions would align their processes to MOD-025-2 when it takes effect.
Response: The GVSDT thanks you for your comment.		
Duke Energy	Yes	There have historically been regional differences in unit criticality size.
Response: The GVSDT thanks you for your comment.		
Luminant Power	Yes	
New York Independent System Operator	No	In the NPCC region Directory 9 and 10 were written to meet the original obligations of MOD-024 and MOD-025. These directories are more specific or more stringent than MOD-025-2.
Response: The GVSDT thanks you for your comment. The original MOD-024 and MOD-025 standards required entities to do verification as directed by the regional entities. In response to a FERC directive, the revised standard now specifies requirements that apply to all entities as a continent-wide standard. If a region determines a technical variation is required, then the region can propose a variance in accordance with the Standard Processes Manual. FERC has indicated that it will generally accept regional variances that address performance not addressed in a continent-wide standard, and technically-justified performance that is more stringent than the performance in the continent-wide standard.		
American Electric Power	No	With respect to reactive power, AEP is not aware of any regional variances that would be required for this standard.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)	No	
Midwest Reliability Organization's	No	

Organization	Yes or No	Question 12 Comment
NERC Standards Review Forum (NSRF)		
SERC Planning Standards Subcommittee	No	
Idaho Power-Power Production	No	
PPL Generation	No	
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
Public Service Enterprise Group	No	
SERC Generation sub-committee	No	
Arizona Public Service Company	No	
Southern Company	No	
Tennessee Valley Authority GO	No	
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	

Organization	Yes or No	Question 12 Comment
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy	No	
BC Hydro	No	
Northeast Utilities	No	
Constellation Power Generation	No	
Consolidated Edison Co. of NY,	No	

Organization	Yes or No	Question 12 Comment
Inc.		
Wisconsin Public Service Corp	No	
ISO New England	No	
Manitoba Hydro	No	
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren	No	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)

13. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration: Major conflicts were not reported between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.

Organization	Yes or No	Question 13 Comment
PPL Generation	Yes	Ref. the inputs made above, there should be just one VAR test, with a single set of results going to all parties.
Response: The GVSDT thanks you for your comment. The standard requires the GO and TO to provide the information to the TP. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the operations planning and Real-time operations time horizons. Per the NERC Reliability Functional Model (V5, Page 25), the Transmission Planner has the following relationships with other entities : **2. Collects information including:** **c. Generator unit performance characteristics and capabilities from Generator Owners.** **5. Coordinates the evaluation of BES expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.** **6. Reports on and coordinates its BES expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.**		
FirstEnergy	Yes	Regional Entities such as RFC currently have Real and Reactive standards in place for its members and will need to evaluate the need to keep their standard or revise it to remove any inconsistencies that may exist. One inconsistency is the periodicity of verification for real power.
Response: The GVSDT thanks you for your comment. RFC has informed the GVSDT that: **It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards once the NERC Board of Trustees approves the NERC MOD-025-2 standard. The purpose of this review is to ensure redundant and less restrictive requirements are either revised or**		

Organization	Yes or No	Question 13 Comment
considered for retirement from the RFC standards in accordance with the Reliability First Reliability Standards Development Procedure.		
Exelon	Yes	Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements.
Response: The GVSDT thanks you for your comment. Item 2.2 in Attachment 1 states: "Verify Reactive Power of all generating units, other than wind and photovoltaic, for maximum over-excited (lagging) and under-excited (leading) Reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear units are not required to perform Reactive Power verification at minimum Real Power output."		
Ameren	Yes	There may be a conflict with MISO Module E as it relates to duration of the testing, e.g. one hour versus longer than hour duration.
Response: The GVSDT thanks you for your comment. If the MISO duration is longer, then there will not be any issue with meeting the one-hour requirement in MOD-025.		
Oncor Electric Delivery Company LLC	Yes	In the ERCOT Region, resource testing and most all communications regarding unit performance is facilitated by the Independent System Operator who is the Planning Authority. This is consistent with current, ERCOT protocols, operating guide and planning guide.
Response: The GVSDT thanks you for your comment. MOD-025 requires the GO to provide information to the Transmission Planner. As envisioned, if the Planning Coordinator (Authority) needs the information provided, the Transmission Planner will provide per the relationships in the functional model.		
Austin Energy	Yes	See the response to Question 6.
Manitoba Hydro	Yes	A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
Response: The GVSDT thanks you for your comment. Entities are responsible for verifying only those units applicable under the Facilities section of		

Organization	Yes or No	Question 13 Comment
this standard. The GVSDT is aware that Canadian entities may have a different Implementation plan since they are not FERC jurisdictional.		
Chelan County PUD		Voltage schedule requirements may conflict.
Response: The GVSDT thanks you for your comment. The GVSDT cannot respond fully to this comment without more information.		
Idaho Power-Power Production	No	No conflict, but as stated before, it seems to be redundant with FAC-008, FAC-009 and the existing WECC validation policy.
Response: The GVSDT thanks you for your comment. Please see response to earlier comment.		
American Electric Power	No	AEP is not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
Response: The GVSDT thanks you for your comment.		
ISO New England	No	The obligations set by this Standard are less stringent for Generator Owners/Operators than those contained in ISO-NE's Tariff. In addition, FERC's Standard Generation Interconnection Rules make clear that material changes to generation facilities (which would include changes to reactive power capabilities) must be reported to the Transmission Service Provider prior to the change being made. The Standard Drafting Team should consider whether language is appropriate to make clear that the Standard is not meant to displace obligations to report reactive power capabilities already contained in Transmission Service Providers' tariffs.
Response: The GVSDT thanks you for your comment. The standard is designed to be a verification of capability for long-term planning studies and have no interaction with any tariffs.		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)	No	

Organization	Yes or No	Question 13 Comment
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	No	
SERC Planning Standards Subcommittee	No	
Dominion	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
SERC Generation sub-committee	No	
Arizona Public Service Company	No	
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	No	
Luminant Power	No	
Salt River Project	No	
PacifiCorp	No	

Organization	Yes or No	Question 13 Comment
South Carolina Electric and Gas	No	
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator	No	
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Wisconsin Electric	No	
Great River Energy	No	
BC Hydro	No	
Northeast Utilities	No	

Organization	Yes or No	Question 13 Comment
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	No	
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
GE Energy	No	
Duke Energy	No	
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
APS		being intentionally left blank (no answer to be provided)
Response: The GVSDT thanks you for your comment.		

14. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please provide a reference to the section, requirement, or subrequirement that you believe should be changed, added ,or deleted and the rationale for your proposal.

Summary Consideration: A number of commenters suggested revisions for clarity that were accepted by the GVSDT. Minor changes were made to the standard to incorporate many of those suggestions. Language was added to recommend that the AVR be in automatic control while conducting reactive capability testing, but that Reactive capability testing must be done even if the AVR is not available.

The following language was also added to allow flexibility if 90percent of the generation is not available when testing wind turbines or photovoltaic inverters.

If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold. percent

Organization	Yes or No	Question 14 Comment
Associated Electric Cooperative, Inc.	Yes	1) We agree with the stated purpose of this standard however we don't believe that this standard, as written, meets the intent related to reactive capabilities. We have already spent significant time, effort and money to perform reactive capability testing, and the test results provide little value toward establishing appropriate capabilities for planning purposes. Additionally, this testing puts our equipment and the BES at risk. It appears that this standard will make us repeat this effort with additional requirements for reactive capability testing at Pmin. 2) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 3) The standard needs to allow the inclusion of engineering analysis to supplement or replace testing when appropriate (see comments to question #10). 4) Instead of the periodic requirements, there needs to be a change based validation requirement. If a plant is materially changed (such as significant equipment changes or performance degradation), there needs to be a new validation done. 5) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent

Organization	Yes or No	Question 14 Comment
		information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 6) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 7) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 8) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 9) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 10) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 11) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 12) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 13) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 14) Note that the standard is only applicable to the GO/GOP, but needs involvement from the TO/TP/TOP to adequately complete a validation. Thus the standard needs to address the responsibilities of those entities for it to adequately address the issue of model validation. It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 15) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creates a continuous state of testing across the BES. We question if this approach

Organization	Yes or No	Question 14 Comment
		really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators.

Response: The GVSDT thanks you for your comment.

(1) Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. This data verification is a result of a FERC directive in paragraph 1321 which states:

1321. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for Real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW Loading. However, other than baseLoad units, most generating units rarely operate at full MW Loading. It is unclear what reactive capability is available throughout a unit's Real Power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's Real Power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.

(2) Response: The standard only requires testing once every 5 years. Operating a low capacity factor unit for 1 hour every five years should not be a burden.

(3) Response: Engineering analysis is allowed to supplement operating data as specified in Note 2 of Attachment 1.

(4) Response: The GVSDT agrees that material changes should require verification, and the standard calls for this specifically in item 2 of Attachment 1, "Periodicity for conducting a new verification". The GVSDT further believes that even if changes do not occur, verification is performed at least every five years to assure that equipment can still reliably function.

(5) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.**

(6) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.**

(7) **Response: The GVSDT has changed the standard to clarify this point. The phrase, "could normally be expected" was changed to "are normally expected."**

(8) **Response: The GVSDT believes that 90 days provides sufficient time and is not a hardship.**

(9) **Response: This is standard language. The GVSDT believes language is clear.**

(10) **Response: The GVSDT has modified the standard's VSLs for clarity by changing "date data was recorded" to "date of verification".**

Organization	Yes or No	Question 14 Comment
(11 **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level. VSLs should identify a wide range of possible noncompliance.** (12) **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level.** (13) **Response: The GVSDT believes that the 6 month time frame specified is appropriate.** (14) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. Note that the intent of MOD-025 is to verify the accuracy of specific data used in long-range planning, not Real-time operations. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States, FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.)** (15) **Response: Normal operational data is allowed by the standard.**		
SERC Generation sub-committee	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate (see comments to question #10). It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5 year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2.

Organization	Yes or No	Question 14 Comment
		5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and thus we also request that this requirement be revised to allow additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 11) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 12) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 13) It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations) .As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 14) This standard establishes a periodic generator testing regime which, when implemented on a large number of generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach to verify reactive capability for most generators. Targeted testing can then be

Organization	Yes or No	Question 14 Comment
		used on a limited basis.

Response: The GVSDT thanks you for your comment.

(1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit for one hour every five years should not be a burden.**

(2) **Response: The GVSDT believes that engineering analysis alone does not provide verification of equipment.**

(3) **Response: The five- year interval was chosen to ensure that equipment degradation or inadvertent or unknown changes would be identified.**

(4) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.**

(5) **Response: The intent of the standard is to capture the normal operating capability.**

(6) **Response: The GVSDT agrees and has modified the standard as suggested. The phrase, "could normally be expected" was changed to "are normally expected."**

(7) **Response: The GVSDT has modified the language to improve clarity. The GVSDT believes the 90-day time period specified is sufficient for submitting data**.

(8) **Response: This is standard language. The GVSDT believes language is clear.**

(9) **Response: The GVSDT has modified the standard's VSLs for clarity by changing "date data was recorded" to "date of verification."**

(10) **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level. VSLs should identify a wide range of possible noncompliance.**

(11) **Response: The GVSDT believes that all the items in the "or" statement are needed to characterize a possible severe violation level.**

(12) **Response: The GVSDT believes that the six- month time frame specified is appropriate given most Transmission Planners run simulations annually. Extending the time period to one year increases the likelihood that the changes discovered may not exist when performing the next simulation.**

(13) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. Note that the intent of MOD-025 is to verify the accuracy of specific data used in long-range planning, not Real-time operations. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States. FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the**

Organization	Yes or No	Question 14 Comment
Reliability Standard to be a matter of good utility practice.) (14) **Response: Normal operational data is allowed by the standard.**		
Tennessee Valley Authority GO	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate. It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5-year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used. We suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results. Consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded"

Organization	Yes or No	Question 14 Comment
		to "from the verification date" each time it is used (7 times). 10) Revise attachment 1 section 5.1 and 5.2 to change "last more than 6 months" to "last more than 1 year," to align with the typical long-term planning horizon. 11) It is noted that MOD-11, which is supposed to clarify modeling data requirements, has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 12) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators. Targeted testing can have application on a limited basis.

Response: The GVSDT thanks you for your comment.

(1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit one hour every five years should not be a burden.**

(2) **Response: The standard allows engineering analysis to supplement operating data as specified in Note 2 of Attachment 1. Since engineering analysis cannot verify the performance of equipment, it is not a substitute for staged testing or operational data.**

(3) **Response: The five-year interval was chosen to ensure that equipment degradation or inadvertent or unknown changes would be identified.**

(4) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.**

(5) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.**

(6) **Response: The GVSDT has changed the standard to clarify this point. The phrase, "could normally be expected" was changed to "are normally expected."**

(7) **Response: The GVSDT believes that 90 days provides sufficient time and is not a hardship.**

(8) **Response: This is standard language. The GVSDT believes language is clear.**

(9) **Response: The GVSDT has modified the standard's VSLs for clarity by changing "date data was recorded" to "date of verification."**

(10) **Response: The GVSDT believes that the six- month timeframe specified is appropriate.**

(11) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment,**

Organization	Yes or No	Question 14 Comment
and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. Note that the intent of MOD-025 is to verify the accuracy of specific data used in long-range planning, not Real-time operations. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States. FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.) (12) **Response: Normal operational data is allowed by the standard.**		
Southern Company	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be run for testing. Please consider a provision for excluding these requirements for units that do not regularly run unless verification using engineering analysis is allowed. 2) Each of the methods of verification proposed have merits and deficiencies. For staged testing, there exists the risk of tripping a unit during testing. System conditions which allow for the maximum reactive power output production/absorption are extreme system voltage conditions - precisely where it is undesirable to perform such testing or trip a unit. Staged testing or verification using operational data during normal system voltage conditions will result in reactive limits constrained by system conditions (not representative of the actual unit capabilities for extreme voltage conditions when the reserve Var capabilities are needed most). Staged testing may, however, reveal unknown thermal or mechanical problems which, while are good to know, are maintenance related and are not the primary objective of the standard which is verification of reactive capability for use in planning models (Long Term Planning Horizon). But, if system constraints during staged testing do not permit a unit to reach the reactive limits the unit could reach during extreme system voltage conditions, one could argue the results of the test are inconclusive in terms of meeting the reliability objective of the standard. Our experience has shown that unit reactive limits for extreme voltage conditions (when the reserve Var capabilities are needed most) can best be determined using engineering analysis. It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC Regional Criteria for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The test interval and new unit test requirement described in Attachment 1, part 5 should be included in the

Organization	Yes or No	Question 14 Comment
		main standard requirement section rather than in the staged test details. However, we believe re-verification every 5 years is too frequent. We agree that re-verification is appropriate for significant changes that impact the real or reactive capability by more than 10%, but we question the six month criteria. For the Long Term Planning Horizon, one year would be more appropriate. 4) In R1.2 and R2.2 the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP (> 30 days late)

Response: The GVSDT thanks you for your comment.

(1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit one hour every five years should not be a burden.**

(2) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment,**

Organization	Yes or No	Question 14 Comment
and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Engineering analysis alone does not verify the functionality or health of equipment and thus cannot serve as a verification method. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. (3) **Response: Guidance was received from NERC on how to develop an attachment referenced by requirements. The attachment contains procedural elements needed for satisfying the requirements. The requirements require verification of performance and timely reporting of data to the Transmission Planner. The GVSDT believes that the six-month timeframe specified is appropriate.** (4) **Response: The GVSDT agrees and has modified the standard to use the same wording in both the measures and requirements.** (5) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.** (6) **Response: The GVSDT has changed the standard to clarify this point. The phrase, “could normally be expected” was changed to “are normally expected.”** (7) **Response: The GVSDT believes that 90 days provides sufficient time and is not a hardship.** (8) **Response: This is standard language. The GVSDT believes language is clear.** (9) **Response: The GVSDT has modified the standard’s VSLs for clarity by changing “date data was recorded” to “date of verification.”** (10) **Response: The GVSDT believes that all the items in the “or” statement are needed to characterize a possible severe violation level. VSLs should identify a wide range of possible noncompliance.** **(11) Response: The GVSDT believes that all the items in the “or” statement are needed to characterize a possible severe violation level.**		
Duke Energy	Yes	1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) MVAR validation issues should be combined with generation FAC-8 issues to eliminate confusion that these separate standards have caused. 3) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 4) We suggest revising Requirements R1.3 and R2.3. Data should be submitted to the TP at the next annual update provided on MOD-010 model data. 5) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 6) It is noted that MOD-11 which is supposed to clarify modeling data requirements has not yet been

Organization	Yes or No	Question 14 Comment
		completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 7) Since GO/GOPs do not always model electrical systems, nor participate in interconnected system models groups such as the Master Model Working Group (MMWG), there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF is considering a collaboration to do so.
Response: The GVSDT thanks you for your comment. (1) **Response: The standard only requires testing once every five years. Operating a low capacity factor unit one hour every five years should not be a burden.** (2) **Response: FAC-008 deals with Facility ratings methodology whereas MOD-025 is concerned with verification of those ratings. THE GVSDT is unsure of the confusion that is indicated.** (3) **Response: The intent is to capture the normal operating condition and not to increase hydrogen pressure or make other alteration just for testing.** (4) **Response: The MOD-025 standard requires the data to be submitted within 90 days after verification. This time period may or may not correspond with MOD-010 data submission requirements.** (5) **Response: The GVSDT believes that the six month timeframe specified is appropriate.** (6) **Response: Since system conditions can be a limiting factor, no test can assure that the rated values of the excitation equipment and generator will be reached during a test. The GVSDT believes that testing as close as possible to the Pmax and Qmax point will identify most issues with equipment, and the reliability purpose will be achieved. Through Order 693, the FERC has required testing at other points in order to help define the entire performance curve for the unit. Please advise if the commenter has specific suggestions on how to better achieve this reliability purpose. While MOD-011 was not approved by FERC, it is effective in some Canadian Provinces and in the United States. FERC advised that entities "should" comply with MOD-011. (From Order 693: In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.)** (7) **Response: The creation of the guide suggested is outside the scope of the project SAR. The commenter may consider submitting a SAR for this issue.**		
Ameren	Yes	(1)If a demonstrated value is less than the corresponding expected value, then the generator owner should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Owners for system modeling use.

Organization	Yes or No	Question 14 Comment
		(2) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (3) We understand the 20% and 10% variances allowed in the draft are for testing purposes. However, it's unclear how they should be used. For example, are they relative to the results at time of seasonal peak, or just maximum output at the time of testing? (4) Notes 1 and 2 should be Requirements. It is difficult to determine how compliance with footnotes will be audited. (5) Engineering judgment should be clearly allowed when meter data (for example no meter at the high side of a GSU), auxiliary data, etc. is not available as required in Attachment 1. (6) Sister Unit exemptions should be allowed for generators that are essentially identical and operated in an identical fashion.
Response: The GVSDT thanks you for your comment. (1) **Response: Calculated values do not provide verification of equipment capability.** (2) **Response: The GVSDT believes that the diagram in Attachment 2 clearly identifies the intent of the term "point of Interconnection."** (3) **Response: The GVSDT has revised the language for clarity. The revised standard, Attachment 1, step 2 states:** **"Operational data from within the two years prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is at least 90percent of a previously staged test that demonstrated at least 50percent of the capability shown on the appropriate Dee-Curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (for example capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** (4) **Response: Notes 1 and 2 are informational and do not contain actions that are auditable. Note 2 specifically states that it is not required by the standard.** (5) **Response: The standard allows engineering analysis if metering does not exist at a particular location.** (6) **Response: The standard requires verification only once every five years. The GVSDT believes to maintain reliability every unit should be verified once every five years.**		
SERC Dynamics Review Sub-committee	Yes	The VSL for R2 is missing a needed component. The Severe category needs to include the following: "The Transmission Owner verified and recorded the Real and Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded."

Organization	Yes or No	Question 14 Comment
		GO's should be required to provide expected values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. Item 3.4 in Attachment 1 refers to Transmission Owner. It should say Transmission Planner to match Requirements 1 & 2. Only one verification is needed for sister (identical) units. The standard currently requires verification for all units.
Response: The GVSDT thanks you for your comment. (1) **Response: A synchronous condenser does not have Real Power capability.** (2) **Response: Engineering analysis is allowed. Expected values are not required because the GVSDT does not believe the results constitute verification.** (3) **Response: This has been revised to Transmission Planner.** (4) **Response: The standard requires verification only once every five years. The GVSDT believes to maintain reliability every unit should be verified once every five years.**		
IRC Standards Review Committee (joint comments)	Yes	The proposed MOD-025-2 standard appears to violate many conventions, such as: o The use of Attachments for mandating requirements o The combinations of different actions in the same requirement o The mandating of specific formats
Response: The GVSDT thanks you for your comment. **(1) Response: The requirement would be cumbersome without including the attachment. The use of the attachment improves requirement clarity and is supported by NERC's standards staff.** **(2) Response: Requirement R1 has been split into separate requirements to resolve this concern.** **(3) Response: The standard calls for data to be submitted and a sample form is provided for reference. The GVSDT has included the information necessary for meeting the reliability objective of the standard. Entities can use their own form for submitting data and this is clear in the revised standard**		
Pepco Holdings Inc Affiliates	Yes	Should Attachment 1 Sec 5 be added to the standard list of requirements instead of part of the attachment? It

Organization	Yes or No	Question 14 Comment
		appears that this section is more than just additional details on verification and reporting. In the project background information it is stated “. If regions have generating units that are connected at under 100 kV that are important to the reliability of the system due to some local consideration, then the region has the authority to require that those units be verified if they so choose.” This capability should be noted directly in the standard.
Response: The GVSDT thanks you for your comment. **(1) Response: The requirement states that verification is performed in accordance with the procedure listed in Attachment 1. The GVSDT believes the attachment contains procedural elements needed for satisfying the requirements. The requirements require verification performance and timely reporting of data to the Transmission Planner.** **(2) Response: This is a part of the delegation agreements and the NERC Rules of Procedure.**		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	Please consider the following comments: 1. Attachment 1, Item 2 - Add the adjective “gross” to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. 2. Attachment 1, Item 2 - Modify the wording of “with all auxiliary equipment needed for expected normal operation” to “with all auxiliary and voltage regulation equipment, such as reactive power compensation, needed for expected normal operation and voltage regulation” to assure that any reactive power compensation equipment (e.g. capacitor banks, SVCs, STATCOMs) are not overlooked and omitted from the verification data. This added text is particularly needed for wind generation situations. 3. Attachment 1, Item 2 - We would prefer the acceptable verification with operational data to be 10%, rather than 20%. 4. Attachment 1, Item 2 - Expand the text of “expected value” to “expected maximum gross Real and Reactive Power Generator capability values” to add more clarity. 5. Attachment 1, Item 2.1 - Add the adjective “gross” to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. 6. Attachment 1, Item 2.1 - Replace the wording “at rated gross Real Power capability” with “at the generating unit’s normal expected maximum Real Power capability” and drop the footnote reference. 7. Attachment 1, Item 2.2 - Add the adjective “gross” to the Real Power and Reactive Power references for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values.

Organization	Yes or No	Question 14 Comment
		8. Attachment 1, Item 2.4 - We think that both "2.1 and 2.2" should be referenced for the over-excited data. If this is incorrect, then please explain why 2.1 should be omitted. 9. Attachment 1, Item 2.6 - Add an Item 2.6 of "Record the generator step up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer". This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements were taken. We are aware that this oversight has already occurred several times. [Add Point "F" (pointing to the generator step up transformer) to the Verification Information Reporting Form in Attachment 2 to accommodate and remind the Generator Owner or Transmission Owner to record these losses, when it is needed.] 10. Attachment 1, Item 3.4 - Correct the functional entity reference from "Transmission Owner" to "Transmission Planner". Revise the wording to allow the Generator Owner or Transmission Owner to report, "The ambient air temperature and/or ambient water temperature at the end of the verification period". [Require that the 'basis' ambient air temperature and/or ambient water temperature associated with the reported gross generator Real Power capabilities be stated on the Verification Information Reporting Form along with a correction factor if any, to allow the Transmission Planner to correct the Real Power capability to different ambient temperatures, if needed.] 11. Attachment 1, Item 3.7 - Add an Item 3.7 of "The GSU transformer losses if the verification measurements were taken from the high side of the GSU transformer." This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements are taken". 12. Attachment 1, Item 5.3 - Add revise the wording, "within one year of their commercial operation" to "within one year of their commercial operation or as scheduled by the applicable Transmission Planner" to allow the exception of an earlier or later due date when it may be appropriate and agreed to be the affected Transmission Planner. 13. Attachment 2, Item A - Add a note that the individual unit values should be reported separately whenever the verification measurements were taken at the individual unit. In most cases, the individual units are modeled separately (including compound units) in the power flow cases and the loss of individual units are simulated in system planning assessments. So, if the verification data was collected in a manner that would allow individual unit power capability verification, then the reporting form should not direct the Generator Owner or Transmission Owner to mask this information. 14. Attachment 2, Item F - As noted above, add a Point "F" (pointing to the generator step up transformer) to the Verification Information Reporting Form to refer to the GSU transformer losses. Also add a Point "F" row to the data table with entries that indicate to provide the GSU transformer MW and MVAR losses

Organization	Yes or No	Question 14 Comment
		when the verification data was based on measurements that were taken from the high side of the GSU transformer. Otherwise, GOs and TOs that base verification values on measurements from the high side of the GSU transformer may forget to make the proper correction when they calculate the gross values for Point "A", as others have historically done. The scope of this standard does not include the verification of high voltage power flow controllers that are connected to the transmission system at 100 kV or above. We propose that a Standard Authorization Request (SAR) be created to address the power capability verification gap that is not being filled with this standard. The test form has remarks space for reactive limit constraints but not for real power constraints. 15. Attachment 1 , #2, the use of the word "all" auxiliary equipment is unnecessary and is over reaching, the Requirement is for expected normal operation. Recommend deleting "all" from this sentence. 16. Attachment 1, # 2.1, should the SDT give an alternate threshold if "90%" could not be achieved during the testing window?

Response: The GVSDT thanks you for your comment.

(1) Response: The Attachment 2 form makes the data requirement clear. Other values are recorded in addition to gross values.

(2) Response: The GVSDT believes the current verbiage, "with all auxiliary equipment" is sufficient to address this concern. The capacitor banks, SVCs, and STATCOMs are not part of this standard. The GVSDT recognizes these are important reactive resources and has suggested a SAR be created to address them.

(3) Response: The GVSDT has modified the Attachment to use 10percent of the last staged test rather than 20percent.

(4) Response: The GVSDT has removed the "expected value" phrase. The sentence now reads "…is at least 90percent of a previously staged test where a voltage limitation was reached"

(5) Response: The Attachment 2 form makes the data requirement clear. Other values are recorded in addition to gross values.

(6) Response: The GVSDT concurs and has revised the language as suggested.

(7) Response: The Attachment 2 form makes the data requirement clear. Other values are recorded in addition to gross values.

(8) Response: Item 2.1 was omitted from the over-excited case in Item 2.4 because it is covered in Item 2.3.

(9) Response: The GVSDT concurs and has revised the language as suggested and added a section to Attachment 2 for recording the value.

(10) Response: The GVSDT has corrected the reference to indicate the Generator Owner as the entity to record the ambient conditions in case there is a need to perform a correction... The GVSDT has also revised the ambient condition correction language.

(11) Response: The GVSDT concurs and has made the revision suggested.

Organization	Yes or No	Question 14 Comment
(12) Response: The GVSDT believes this suggestion adds ambiguity to the standard and may create compliance issues. The one-year requirement will be retained. **(13) Response: The GVSDT concurs and has made the revision suggested.** **(14) Response: A section was added to Attachment 2 for recording the value for the GSU losses. The commenter is encouraged to submit a SAR to address the remainder of this comment. The remarks space can be used to document either Real or Reactive power constraints.** **(15) Response: The GVSDT disagrees and has retained the word "all."** **(16) Response: The GVSDT has added the following verbiage to Attachment 1, Item 2.1 to address this concern:** **"If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the ninety percent threshold."** **If a Facility has an issue that affects the output by 10percent for more than six months, the Facility is to be re-rated per Item 5.1 in Attachment 1.**		
SPP Reliability Standards Development Team	Yes	VSLS for R2 there is an extra applicable in the chart. Would suggest removing.
Response: The GVSDT thanks you for your comment. The chart has been corrected.		
SERC Planning Standards Subcommittee	Yes	If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. "The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers"
Response: The GVSDT thanks you for your comment. The GVSDT believes that calculations do not provide verification that a unit or Facility can reach the specified operating point.		
Idaho Power-Power Production	Yes	1. The language in the Applicability Section 4.2.1, implies that the standard applies to only synchronous condensers in generating facilities. Please clarify. 2. As stated before, we believe that FAC-008 and FAC-009 specify our generator have a normal and emergency rating. The standards should use similar language in requiring validation of capability.

Organization	Yes or No	Question 14 Comment
		However, our regional policy required by MOD-010, specifies validation of the generator reactive capability, thus we believe this standard is redundant and not needed. That is unless MOD-010 is going to be retired. 3. Note 1 in Attachment 1 states that the data point may not match the manufacturer capability curve or the verified values for the MOD-010 standard. We question what the point of this standard is if not to validate. Note 1 mentions other items that might be discovered during the validation required by this standard, but we believe those benefits are achieved by our existing validation policy.
Response: The GVSDT thanks you for your comment. **(1) Response: The GVSDT has revised 4.2.1 to state:** "Individual generating unit greater than 20 MVA (gross nameplate rating) in a generating Facility or synchronous condenser greater than 20 MVA (gross nameplate rating) connected at the point of Interconnection at 100 kV or above." **(2) Response: The GVSDT is not aware of any effort to retire MOD-010. MOD-025 requires verification of Real and Reactive power capability of a unit or synchronous condenser. The verification is performed for normal capability, not emergency capability. FAC-008 and FAC-009 specify a methodology for developing Facility ratings whereas MOD-010 pertains to data and equipment characteristics, not validation requirements. The standards do not duplicate requirements.** **(3) Response: The GVSDT believes that reactive power limitations originating inside the generating station (e.g., hydrogen pressure, thermally sensitive generator, voltage regulator settings, excitation problems, etc.) need to be verified by testing. MOD-025 is a verification standard. Note 1 addresses the possibility that a unit may not be able to reach the D-curve value because of limitations outside owner control. MOD-010 is not a verification standard.**		
Santee Cooper	Yes	Attachment 1 Item 1 requires testing of units that are 20 MVA and above to be tested a second time if they are tested as part of the aggregate.
Response: The GVSDT thanks you for your comment. The GVSDT disagrees with your assertion. Units rated greater than 20 MVA are individually verified. Units 20 MVA or less can be verified individually or in aggregate. Item 1 states: "For units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit greater than 20 MVA (gross nameplate rating)."		
PPL Generation	Yes	PPL offers the following comments on Attachment 1:

Organization	Yes or No	Question 14 Comment
		1. Att. 1, para. 2: Change the final sentence to end, "within 20% of the expected real and reactive power values."Reason: Clarification Att.1, footnote to para. 2.1: Change "normal expected maximum" to "normal," and "at the time of the verification" to "for the ambient conditions during the verification."Reason: Clarification. The normal output of a unit is often not its (emergency) maximum generation, and the word "ambient" works better than "time." 2. Att. 1, para. 2.1, 1st sentence: Change "at rated gross Real Power capability" to "within 20% of the Real Power capability."Reason: Clarification, see the comment above to para. 2. Also, the terms capability and rating have different meanings. 3. Att. 1, para. 2.1, last sentence: Change "possible" to "practical" 4. Att. 1, para. 2.2: Change exception in 1st sentence to "other than wind, photovoltaic and peaking (capacity factor < 10%)."Reason: Given that peaking units typically operate only during periods of maximum demand, it can be difficult to establish a realistic min power expectation, this exercise would add little or no value, and such testing would be unnecessarily economically burdensome. 5. Att.1, para. 2.3: Add at end, "for baseload units. Values for peaking units (<10% capacity factor) may be recorded as soon as they are reached. Reason: The dispatch volatility of peaking units can make a one-hour hold-period unnecessarily economically burdensome. 6. Att. 1, para. 2.5: Add at end, "if attainable. Otherwise a 10% variation is acceptable. Reason: Hydrogen pressure can vary, and minor disturbances should not disqualify an otherwise-acceptable test. 7. Att. 1, para. 3.2: Clarification is needed. Is the standard saying that a special-for-test voltage schedule should be established with the RTO? 8. Att. 1, para. 3.3: Add at the end, "one or the other of these values may be calculated, if metering is not present at both locations."Reason: Same concept as para. 4.1. 9. Att. 1, Note 1, 1st sentence: Add at the end, "or unit auxiliary system voltage limits or facility operational practices." Make the same change also for "transmission system conditions" in the third sentence. Reason: VAR testing involves creating abnormal voltages at the generator terminals and in the feeds to auxiliary equipment. Drop-out of aux motors can constitute the practical test limit. It is appropriate to apply safety margins in this respect (ref. facility operational practices), lest units be at risk of tripping in the course of conducting a reliability test. 10. Att. 1, Note 2: Clarification is needed regarding the less-restrictive conditions being referred-to. 11. Att. 1, para 3.4: Replace "and a correction factor...if needed" with "and, if requested, correction to other ambient conditions."Reason: Correction often involves more than a simple multiplication factor, especially

Organization	Yes or No	Question 14 Comment
		when using a thermodynamic computer model for this purpose. This exercise includes truncating corrections to lower ambients for GSU and generator limits, if necessary. 12. General: The generator OEM D-curve constitutes a rating, not a capability, and is applicable only at rated voltage. VAR testing involves identifying a capability at abnormal voltages, and is thus likely to rarely if ever match the D-curve. 13. General: Where the RTO has an effective VAR testing program in place (as is the case for PJM) the results should be acceptable as-is for NERC compliance purposes, lest there be created two different tests, resulting in reporting of two different reactive capabilities to two different entities.

Response: The GVSDT thanks you for your comment.

(1) Response: The GVSDT has revised the sentence to state: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50percent of the capability shown on the associated D-Curve. percent

(2) Response: The GVSDT has removed the footnote and revised the sentence based on other stakeholder comments:

2.1. Verify Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications.

(3) Response: See responses above.

(4) Response: We concur with adding wind and photovoltaic and have made the revision suggested. We do not concur with providing the exception to other units as the standard applies to applicable Facilities that meet registration criteria. Item 2.2 also contains the phrase, "minimum Real Power output at which they are normally expected to operate." If a peaking unit only operates at maximum output, then this is how the unit should be verified.

(5) Response: The GVSDT does not have evidence that exempting these additional units will not adversely impact reliability. The verification is only required to be performed for one hour every five years. The GVSDT does not believe this is an economically burdensome requirement.

(6) Response: Paragraph 2.5 does not specify a pressure or bandwidth. It is expected that verification will be performed at the normal pressure. In other words, at the pressure the unit usually operates.

(7) Response: The standard does not specify a special voltage schedule. Item 3.2 only states to record the voltage during the test. This voltage value may be the normal voltage schedule.

(8) Response: The GVSDT concurs and has revised item 3.3 by adding: "If only one of these values is metered, the other may be calculated."

Organization	Yes or No	Question 14 Comment
(9) Response: The standard does not require testing to exceed voltage limitations and risk equipment damage or jeopardize reliability. **(10) Response: The GVSDT has added the following phrase to the end of the sentence in Note 2: "Than those encountered during the verification," and changed "conditions" to "voltages" to provide clarity. The sentence now states:** **"While not required by the standard, it is desirable to perform engineering analysis to determine expected unit capabilities under less restrictive system voltages than those encountered during the verification."** **(11) Response: The verbiage of item 3.4 is designed to address the FERC Order 693 directive to provide this information. This language has been revised for clarity.** **(12) Response: The standard doesn't require a unit to reach the D-curve value. The D-curve does not reflect all unit limitations that may exist.** **(13) Response: If the requirements of the PJM standard satisfy the requirements of the NERC MOD-025-2 standard, then additional testing should not be necessary.**		
Dominion	Yes	Test form needs to be improved. Provide the form in format that can be electronically completed by the user.
Response: The GVSDT thanks you for your comment. The form was developed as an example. The commenter can develop an electronic form, if desired.		
FirstEnergy	Yes	Regarding Notes 1 & 2 in the standard: Generally we have found that reactive power limitations that originate inside the generating station (hydrogen pressure, thermally sensitive generator, voltage regulator settings, and excitation problems) usually cannot be overcome through engineering analysis on the part of the transmission planning engineer. These types of conditions can only be addressed by the GO. On the other hand, Generator Terminal Voltage limits, or Transmission System voltage Limits can be eliminated using engineering analysis to simulate a more stressed system. Attachment 1, R2 - Assuming there are no transmission system related limitations, how close does the test value for VARs have to come from the expected value to be considered "verified"? Attachment 1, R2.2 - Nuclear units should be exempt from having to test leading VAR capability as this would challenge the plant's licensing limits for safety bus minimum voltage. MOD-025-RFC-01 currently allows this exemption for nuclear plants. Attachment 1, NOTE 1 - For clarity, nuclear plant safety bus voltage limits should mentioned as a reason why D-Curve values may not be met during a test.
Response: The GVSDT thanks you for your comment.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 14 Comment</th></tr>
<tr><td colspan="3">(1) Response: The GVSDT agrees.
(2) Response: The goal of the requirement is to verify the actual Reactive Power capability of the unit, and not necessarily confirm a predetermined capability.
(3) Response: If a nuclear plant has under-excited capability it should be tested within the unit's capability and declared safety margins.
(4) Response: Note 1 has been revised for clarity, and the following sentence was added to Note 1:
"Auxiliary bus voltage limits should be observed"</td></tr>
<tr><td>NERC Staff</td><td>Yes</td><td>The violation risk factors associated with Requirements R1 and R2 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 and R2 should include the operations planning horizon. The SDT should consider use of the word "verification" versus "validation" and assure that the term used in this standard is consistent with other standards.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT agrees and has modified the standard accordingly (VRF's are now Medium)</td></tr>
<tr><td>Public Service Enterprise Group</td><td>Yes</td><td>We have listed several concerns and questions below:
a. We believe that Reactive Power capability at minimum Real Power output needs to be verified when a unit is installed and only verified thereafter when the generator itself is modified. Performing such tests will be difficult to run due to system voltage limitations at minimum Real Power generator output. This would require a modification or Attachment 1, paragraph 2.2, and paragraph 5.
b. For the VSL's for requirement R2, the last paragraph of a Severe VSL should be modified as follows: "The TO verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded."
c. The comments below reference Attachment 1.
i. Paragraph 2 and its subparts would be more easily understandable if companion tables were provided that summarized the information. At last two tables would be helpful - one for traditional</td></tr>
</table>

Organization	Yes or No	Question 14 Comment
		dispatchable resources and one for variable resources. ii. In paragraph 3, whether the verification is staged or operational should be provided. iii. In paragraph 3.2, the requirement to supply the voltage schedule provided by the Transmission Operator would not appear to be applicable for a staged test. Trying to test Reactive Power limits while maintaining a prescribed voltage schedule in not practical.
Response: The GVSDT thanks you for your comment. **(1) Response: The standard allows the GO to test until a system limitation is met. This is the point that should be noted in the "remarks" section of Attachment 2 for the verification data. Equipment ages with use and needs to be re-verified periodically. The GVSDT has determined that testing every 5 years is required to maintain reliability. This comes directly from the previous version of the "fill-in-the-blank" standard. It also matches up well to the PRC-019 proposed standard. Although the two standards are separate it is anticipated that PRC-019 would be done before MOD-025. The MW testing portion of the standard is based on stakeholder consensus in previous posting of the SAR and draft standards. It was anticipated that the MW testing could be completed with little effort while doing MVAR testing.** **(2) Response: The wording in the VSLs has been corrected. However, based on comments from other stakeholders, the timing element was modified so that it is linked to the date of the test rather than the date of the recording.** **(3) Response: The GVSDT tried to develop companion tables but determined that it made the document harder to understand and did not add it to the Attachment. It was also viewed as being prescriptive. Paragraph 3 was revised per your suggestion and two check boxes were added to Attachment 2 for "Staged Test" and "Operational Data". Please see Attachment 2. It is recognized that a larger voltage schedule deviation is required to perform this task and this task should be coordinated with your TOP.**		
Arizona Public Service Company	Yes	The proposed VSL levels are spaced 10 days apart. For a test which is done once in a 5 year, it is unnecessarily restrictive. The minimum spacing between the VSLs should be 90 days. Reporting results 90 days late or even a 180 days late does not cause any concern for a planning horizon study. This data is only needed for such studies and such cases are typically updated annually. The real power verification tests are unnecessary and do not add any value. The peaking unit with less than 5% capacity factor should be exempt.
Response: The GVSDT thanks you for your comment. The GVSDT believes the VSL time frame specified is reasonable and is in alignment with NERC's VSL guidelines. **The FERC Order 693 requires verification of Real Power capability. The GVSDT does not have evidence that exempting the peaking units will not**		

Organization	Yes or No	Question 14 Comment
adversely impact reliability. **Because the verification is only required to be performed for one hour every five years the GVSDT does not believe this is a burdensome requirement.**		
Lakeland Electric	Yes	In the VSL table for Requirement R2, the word “applicable” appears twice in a row in the “Lower VSL” and “Moderate VSL” columns. Propose striking one instance of the word.
Response: The GVSDT thanks you for your comment. The error has been corrected.		
PacifiCorp	Yes	Section 4.2 of proposed Standard MOD-025-2 contemplates the inclusion of large wind farms within the scope of the proposed standard, as it is applicable to generating units above individual and aggregate nameplate rating thresholds (as the commentary seems to indicate is intended). The specific requirements for verifying Real and Reactive Power capabilities, however, do not make any allowance for operating differences of wind generation units. If wind generating resources are to be included within the scope of this proposed standard, then the standard should include express allowances for verification methodologies that are applicable to wind generating units.
Response: The GVSDT thanks you for your comment. The GVSDT believes the standard provides sufficient flexibility for wind farms. The GVSDT does not understand the ‘operating differences’ concern. Further explanation is needed before the GVSDT can provide a response.		
South Carolina Electric and Gas	Yes	If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners.
Response: The GVSDT thanks you for your comment. Engineering analysis is allowed. Expected values are not required because the GVSDT does not believe results obtained constitute verification.		
New York Independent System Operator	Yes	1. Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within its area.

Organization	Yes or No	Question 14 Comment
		Additional NYISO Comments not addressed above for MOD-25-2 Under A. Introduction 2. Section 4 - Transmission Planner should be added under Functional Entities 3. Section 5.1.1 through 5.1.5 and 5.2.1 through 5.2.5 - These requirements should clarify that the Transmission owner requirement is for units that the Transmission owner owns and not for the generators in the Transmission Owners area. Under B. Requirements 4. Section 1.3 - The requirement should either be up to 225 days after the test or 60 days after the end of the test period. Attachment 1 - Verification of Generator Real and Reactive Power Capability 5. Section 1 - There should be some provision for allowing the verification results from small, electrically identical units at the same location to apply to other units in the group. 6. Section 2.1 - It is not practical to determine reactive power at rated gross Real Power capability. The requirement that ninety percent of wind turbines or photovoltaic inverters be online during verification of reactive power should be removed. 7. Section 2.2 - This verification is not needed. 8. Section 2.4 - Please clarify the definition of “limit”. 9. Section 3.2 - Please clarify the definition of “voltage schedule”. 10. Section 3.3 - This data is not needed. 11. o Section 3.4 - Ambient air temperature is not needed for reactive power test results. It is only necessary for certain generators in Real Power tests (combined cycle, combustion and turbine).

Organization	Yes or No	Question 14 Comment
		12. Section 4 - The diagram is not needed. 13. Section 4.1 - For the NYISO, Real Power verifications are conservatively measured as Net output, so no auxiliary loads are required to be reported. Attachment 2 14. Attachment 2 requires an unnecessary level of detail for “Data Type” to be recorded and collected; only gross MVAR, auxiliary reactive power and Net MW readings are required. 15. o What is meant by “MVAR values were adjusted to rate generator voltage”?

Response: The GVSDT thanks you for your comment.

(1) Response: The GVSDT believes the GO/TO, as applicable, is responsible to coordinate verification of all units with its TOP within the verification period identified in the standard. The Implementation Plan calls for various percentages of assets to be verified in each year over the phase-in period.

(2) Response: The TP is not responsible for any of the standard requirements and, therefore, is not listed in the Applicability Section. However, data is submitted to the TP.

(3) Response: The GVSDT believes the wording is clear.

(4) Response: The requirement has been modified for clarity.

(5) Response: The standard requires verification only once every five years. The GVSDT believes to maintain reliability every unit should be verified once every five years.

(6) Response: The GVSDT believes verification of Reactive Power at normal expected maximum Real Power is necessary for reliability. Section 2.1 has been modified to state:

> **”If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold.”**

(7) Response: The FERC Order 693 requires verification at multiple points, and the GVSDT believes verification of four points is necessary to approximate the capability curve.

(8) Response: A limit is the point, edge, or line beyond which something cannot or may not proceed. Examples include the thermal capability curve,

Organization	Yes or No	Question 14 Comment
aux bus voltage limit, voltage regulator limiter, or vibration limit. **(9) Response: Refer to VAR-001-1, Requirement 4.** **(10) Response: The GVSDT respectfully disagrees. This information is relevant for Transmission Planners to run accurate and reliable studies.** **(11) Response: Section 3.4 has been revised to include additional correction factor considerations so the GO must determine which ambient conditions need to be recorded for use as a correction factor for Real Power.** **(12) Response: The diagram was added for clarity.** **(13) Response: The GVSDT believes most generators do not meter net power. The standard allows for approximating auxiliary Load if an entity only meters the net power.** **(14) Response: The GVSDT believes most generators do not meter net power. The standard allows for approximating auxiliary Load if an entity only meters the net power.** **(15) Response: Many modern voltage regulators automatically adjust the under-excited limit to account for low bus voltage. A correction may be necessary to determine the limit for rated voltage.**		
Cowlitz County PUD	Yes	As already stated, Cowlitz questions the reliability benefit of the extensive reactive capability requirements and is currently consulting with Transmission Planners if such extensive data will actually be beneficial in their modeling efforts. It may be better to require data that must be verified though staged testing only after request by the Transmission Planner with a reasonable time frame to obtain the data.
Response: The GVSDT thanks you for your comment. Please refer to the previous response. The FERC Order 693 requires verification of Reactive capability at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.		
Xcel Energy	Yes	It is not clear in the standard if a separate load flow report (Attachment 1) is required for each point of verification, or only for the maximum load, maximum lagging reactive point. Please clarify in the standard.
Response: The GVSDT thanks you for your comment. The GVSDT anticipates that each test point would require a separate Attachment 2 report to be completed.		
Lakeland Electric	Yes	Under the section B. requirements R1, 1.1; it refers us to “attachment - 1” . Under attachment - 1, item 2 - 2.1 it states the following:

Organization	Yes or No	Question 14 Comment
		o Perform verification of real and reactive power capability of all generating units at maximum over excited (lagging) and under-excited (leading) reactive capability at gross real power capability. We would like to propose adding “or to the documented limiting factor of the equipment (generator, voltage regulator, transformer, transmission etc.)”. We want to avoid having to test to the min and max of the capability curve if there is some other limiting factor we can document.
Response: The GVSDT thanks you for your comment. The standard doesn’t require a unit to reach the capability curve value. The capability curve does not reflect all unit limitations that may exist. The limitation that is reached should be recorded on Attachment 2 in the remarks section.		
Exelon	Yes	Nuclear units do not perform under-excited (leading) reactive capability testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements. Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities. Suggest that all exceptions to test performance criteria be pulled forward into body of the Standard. Additional comments for MOD-025-2 Attachment 1 o Step 2.3 - remove reference to "rated real power" - the reactive power test is conducted as a stand alone test using the attainable real power (which is generally governed by ambient conditions at the time of the test). o Step 2.4 - remove reference to "over-excited reactive capability" - the over-excited test is conducted for a minimum of 1 hour o Step 3.4 - remove reference to "correction factor: - this applies to correcting MW as part of the MOD-024 test. Reactive power is tested at the attainable MWe.
Response: The GVSDT thanks you for your comment. **(1) Response: If a nuclear plant has under-excited capability it should be tested within the unit’s capability and declared safety margins. The standard does not require challenging unit capabilities. The following statement was added to Note 1 of Attachment 1 for clarity, “Auxiliary bus voltage limits should be observed”.**		

Organization	Yes or No	Question 14 Comment
(2) Response: The GVSDT has added language to Attachment 1, Section 2.1 to clarify the required full Load test points. **(3) Response: Refer to Attachment 1, Section 2.3. The one-hour over-excited reactive capability test is performed only for the rated Real Power capability test. Step 2.4 refers to verification at minimum Real Power capability.** **(4) Response: The GVSDT modified the language in Attachment 1, Section, 3.4 for clarity and “correction factor” was removed.**		
Georgia Transmission Corporation	Yes	Regarding reactive capability, the SDT has recognized that this standard will not meet the purpose “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability.” Should the standard and/or purpose be adjusted to where they match? Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability. R1.3 is unclear we propose: Submit the recorded data to its Transmission Planner within 90 calendar days of the date the data is recorded.
Response: The GVSDT thanks you for your comment. **(1) Response: The goal of this standard is to model steady state capability of generators and synchronous condensers. Therefore, the standard requirements meet the stated purpose.** **(2) Response: Requirement R1, Part 1.3 has been revised for clarity and the revised language is:** **“1.3. Submit to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.”**		
Wisconsin Electric	Yes	Attachment 1, 2.1 and 2.2: It would be more reasonable to allow for some small variation in real power level around the rated gross real power output and minimum real power outputs, perhaps within +/- 5 percent of these values. This would allow for variability in coal conditions, system voltages, etc. Also, the requirement in 2.1 for 90 percent of wind turbines online may be impractical in many cases. A lower value such as 75 percent may be more reasonable.
Response: The GVSDT thanks you for your comment. Reference Attachment 1, 2.1. Some drift in Load is expected and language was added to account for less than 90 percent of wind turbines being on line.		
Great River Energy	Yes	Please see comments submitted by the MRO NSRF for question #14

Organization	Yes or No	Question 14 Comment
Response: Please see response to above question.		
Constellation Power Generation	Yes	CPG is concerned with the general wording of Attachment 1 as the verbiage is not auditable. For example, Item 2.1 states "Maintain as steady as possible Real and Reactive Power output during verification." The term "steady as possible" is extremely subjective and open to a multitude of interpretations. From a technical perspective, item 3.3 is not auditable because it is assuming that the voltages and the high and low side of the GSU are metered. This is usually not the case. A statement allowing for an entity to report on the requested metered points based on their configuration and allowing for some points to not be answered would be preferable. Likewise, Attachment 2 would require a similar statement.
Response: The GVSDT thanks you for your comment. **(1) Response: The GVSDT has revised Attachment 1, 2.1 for clarity. The revised language states:** "Maintain as steady as practical Real and Reactive Power output during verifications (i.e. make no purposeful Load changes and do not have the unit in automatic Load control)." (2) **Response: The GVSDT has revised Attachment 1, 3.3 for clarity. It is anticipated that some non- metered values would need to be calculated.**		
ISO New England	Yes	1. Effective Dates: This proposal is not well explained and very well may not work. Some concerns that arise: (a) For those GOs that have units in multiple control areas, are they supposed to apply the Implementation Plan for their entire fleet or for their fleet on a per Region basis? This same issue can apply to TOs which may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Transmission Operator should be given the discretion to require and approve a test schedule within its area. (b) For those GOs with only one or two facilities in a region, how will the 5-year implementation plan work? Will the GO with one facility in a region have 5 years to implement (i.e., the 100% rule would not "kick" in until 5 years out, or will the GO with one facility in a region have only 1 year to implement (since 20% of 1 unit would arguably capture the unit). 2. R1.2 and 2.2 All entities should use the same submittal form. Please delete the option for a Generator Owner to develop its own form. 3. R1.3... 90 days is too long for reporting data. Recommend 30 days for providing verification data.

Organization	Yes or No	Question 14 Comment
		4. VSL for R2 should mirror VSL for R1. Specifically R2 doesn't mention submitting >120 days as R1 does. 5. Attachment 1: 1. specify that the AVR must be in service and in automatic controlling voltage if required by the TOP 6. 2. If AVR is not required by the TOP, does the unit still have to test? Under the VAR-001 standard an entity may be exempted by the Transmission Operator from having a functional AVR. Under such an exemption the need for testing should not be required. 7. Attachment 2: move the check boxes to the top so that that someone looking at form knows immediately what type of audit was performed. 8. o There should be VSLs in regards to going more than 66 months between verifications. 9. o Periodicity should be captured in Requirements, not in the Attachment 10. If each test is done on different days, does each test have its own verification date? 11. Please clarify what footnote 1 of Attachment 1 is intended to describe with "normal" with respect to the unit's normal expected maximum Real Power at the time of the verification. 12. o Attachment 1, Section 2.1 states that during wind turbine and photovoltaic verification, 90% must be on line. This should read "with AT LEAST ninety percent of the..."

Response: The GVSDT thanks you for your comment.

(1) Response: The GVSDT believes the GO/TO, as applicable, is responsible to coordinate verification of all units with their TOP(s) within the verification period identified in the standard. The Implementation Plan calls for various percentages of assets to be verified in each year over the phase-in period.

(2) Response: The GVSDT created a sample form, Attachment 2. This form should be modified for each unit.

(3) Response: Because this data is for the long-term planning horizon, the GVSDT believes the timeframe specified is appropriate.

(4) Response: The VSLs have been revised and now include a Severe VSL as proposed for Requirement R2 (R3 in the revised standard).

Organization	Yes or No	Question 14 Comment
(5) Response: Voltage control mode is required by VAR-001. **(6) Response: Attachment 1, 2 states the voltage regulator must in automatic mode for the Reactive Power capability test. If automatic control is not available and is not expected to be available any time soon, the test should be conducted but with caution relative to the generator limits.** **(7) Response: The GVSDT liked the suggestion and has made the change.** **(8) Response: The severe VSL applies in this situation.** **(9) Response: The GVSDT believes the current format is clear. The attachments are an extension of the requirements.** **(10) Response: Yes.** **(11) Response: If a generator goes to full output (not emergency output), that would be considered "normal." This is most likely the declared output of this unit.** **(12) Response: The GVSDT agrees and has modified attachment language to use the proposed, "at least 90 percent".**		
Independent Electricity System Operator	Yes	1. In our previous comments, we raised a concern over the detailed requirements in Attachment 1 which in our view are overly prescriptive. Specifically, the requirements listed in Item 3 of Attachment 1 are too detailed, and some of the items listed in 3.1 to 3.6 are not needed or relevant to the provision of verified data for modeling or BES reliability assessment, but they create unnecessary administrative burden. For example, what would be the use of voltage at the high side of the generator step-up and/or system interconnection transformer(s) and the tap settings of these transformers in the application of the recorded real and reactive capabilities to modeling and reliability assessments? And what would be the required actions if the voltage levels and/or the transformer tap setting in the load flow model or in real time are different from the reported values? Imposing the reporting requirement without a clear statement of the intended use, with justification, is unnecessary and should be dropped. Further, we request clarification regarding the phrase "at the end of the verification period" in 3.1 and 3.3? Does it mean the time when the verification test ends, i.e. at the end of the 1-hour period referred to in Attachment 1, bullet 2.3? 2. If the verification is provided by operational data, what would constitute "the end of the verification period"? 3. We believe Attachment 1 needs only to specify the sustainability (Items 1 and 2) and the periodicity (Item 5). We also respectfully disagree with the SDT's response to our previous comments on Attachment 1. The SDT's view that (excerpt from Comment Report) "The SDT believes that attachment one does not contain requirements but provides clarity to the Requirements of the Standard." is incorrect since it is clearly indicated in Requirement 1.1 to "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with

Organization	Yes or No	Question 14 Comment
		Attachment 1."According to the general rule for NERC standards, an attachment is a part of the standard that must be complied with, and hence any items contained in an attachment are mandatory requirements. With that understanding and with the way Attachment 1 is included in Requirement 1.1 that the items in Attachment 1 are not there for clarity but are requirements that must be complied with, we urge the SDT to remove the entire Item 3 from Attachment 1 as the information required in that item does not add to the intended use of the verified data. 4. We do not have the same concern over Attachment 2 since it is made clear in Requirement 2.2 and in the Attachment itself that use of other forms is acceptable and hence use of the diagram is not mandatory. In Attachment 1, step 2.4 seems to be inconsistent. For the over-excited check, record should be taken at min. and max. real power output (i.e. it should state... data required in 2.1 and 2.2.)The table in Attachment 2 should be improved to match data to be recorded in Attachment 1 (i.e. there should be two columns for MVAR to record lagging and leading reactive power for a given MW). 5. MOD-025 Attachment 1 bullets 2.1 and 2.2 should stipulate that Generator Owners and Transmission Owners conduct verification at generator terminal voltages as close as possible to rated terminal voltage. Finally, the standard should use SI units (e.g. active power not real power, Mvar not MVAR).

Response:

Response: The GVSDT thanks you for your comments. The GVSDT believes that the data requested in Attachment 1, Paragraph 3 reflects the data needed to properly verify the unit/Facility. Most of this data was included in the FERC Directives.

(1) Response: Yes, "at the end of the verification period" means at the end of the one-hour period referred to in Attachment 1, Section 2.3.

(2) Response: For operational data, "the end of the verification period" would be the end of the one hour test, the whole hour of which should be recorded.

(3) Response: The GVSDT agrees that items contained in the attachments are mandatory. The GVSDT also believes that the data required in Attachment 1, Section 3 is necessary for meaningful evaluation of Real Power capability or Reactive Power capability.

(4) Response: Attachment 1, Section 2.4 refers to when the data should be taken, i.e., the data can be taken immediately for the low load over-excited and any under-excited tests. The full load over-excited test is run for one hour and is included in Attachment 1, Section 2.3.

(5) Response: The GVSDT thanks you for your comments. The GVSDT feels that allowing a full range of voltage, within equipment limitations and allowed by the TOP would provide a more reasonable expectation of demonstrating the unit/Facility capability over a greater portion of the D-Curve. Testing "as close as possible" to generator terminal voltage would be too subjective and not allow adequate range on many units. The GVSDT believes that the use of Real and Reactive power is appropriate for this standard. The term "MVAR" has been revised to "Mvar" throughout the

Organization	Yes or No	Question 14 Comment
standard.		
Indeck Energy Services	Yes	For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
Response: The GVSDT thanks you for your comment. The implementation is phased in over five years because testing all units in the same year would be impractical. Since the requirement requires testing only once every five years, it is reasonable to space unit testing.		
Indiana Municipal Power Agency	Yes	IMPA believes that the first sentence of requirement 2.1. does not read correctly in the sense that it is requiring the verification of Real Power Capability at maximum over-excited and under-excited reactive capability at rated gross Real Power Capability. This sentence would make sense if Real was removed at the beginning of the sentence and read "Perform verification of Reactive Power capability of all generating...". Requirement 2.2 covers real power testing requirements. Since Real power needs to be removed from 2.1 then requirement 2.3 needs to have the requirement 2.2 added to it to cover the Real power testing time.
Response: The GVSDT thanks you for your comment. The language of Attachment 1, Section 2.1 has been revised for clarity. The revised language is shown below: **"2.1. Perform verification of Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all generating units at the generating unit's normal (not emergency) expected maximum Real Power at the time of the verifications. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of reactive capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold. Maintain as steady as practical Real and Reactive Power output during verifications."**		
Los Angeles Department of Water and Power	Yes	MOD-025 Attachment 1 Sec. 2.1During normal operations, it is typical to have many wind and solar units not working due to equipment malfunctions such as faults. How will failures that prevent the testing of 90% of equipment integrate with the standard? MOD-025 Attachment 1 Sec. 4Will As-Built Project Drawings suffice for the requirement? The development of

Organization	Yes or No	Question 14 Comment
		new one-line diagrams for a simplified version could have a significant impact because it will require the support of drafting resources which might not be available potentially delaying the submittals of Models and Data Reports. The requirement of directional arrows for Reactive Power Flows can be superimposed on the As-Built drawings. MOD-025 Attachment 1, Sec. 5From a user's perspective, it would be useful to get some language from the ERO that quantifies and qualifies what type of control system conditions would trigger the need for a new model and data verification, and also to have access to a comprehensive sample of a model and data verification test plan. This would allow the user to better manage its compliance implementation phase.
Response: The GVSDT thanks you for your comment. **(1) Response: The language of Attachment 1, Section 2.1 has been revised to allow flexibility.** **(2) Response: See the example in Attachment 2. A very simple drawing is suggested and should not require significant resources to create. If your existing one-line drawings have the information required they may be used as a basis for this standard.** **(3) Response: Attachment 1, Section 5 refers to any change that would affect the Real Power or Reactive Power capability of the unit and makes no distinction between control system changes or limitations from other equipment that would alter the last verified capability by more than 10 percent and would last for more than six months. Some examples triggering retesting would include GSU replacements, excitation system change outs (replacements, upgrades or parameter changes), turbine rotor replacements, turbine control system change outs (replacements, upgrades or parameter changes). Basically, any change that would be expected to have an effect on the capability.**		
Austin Energy	No	
American Wind Energy Association	No	
Tacoma Power	No	None
APS		being intentionally left blank (no answer to be provided)
Response: The GVSDT thanks you for your comment.		
Dynegy Inc.	No	

Organization	Yes or No	Question 14 Comment
Manitoba Hydro	No	
Response: The GVSDT thanks you for your comment.		
Westar Energy	No	
Response: The GVSDT thanks you for your comment.		
Luminant Power	No	
Salt River Project	No	
Tri-State Generation and Transmission, In.	No	
BC Hydro	No	
Northeast Utilities	No	
Consolidated Edison Co. of NY, Inc.	No	
American Electric Power	No	
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	

Organization	Yes or No	Question 14 Comment
Oncor Electric Delivery Company LLC	No	
Gainesville Regional Utilities	No	

Consideration of Comments on Generator Verification (MOD-027-1) — Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the First Posting of MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Project 2007-09). These standards were posted for a 30-day public comment period from June 15, 2011 through July 15, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT expanded the applicability of MOD-027-1 to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Stakeholders were asked whether they were aware of other generation configurations or types that should be covered in the Applicability. The vast majority of industry agrees that all of generation configurations or types that should be included in the Applicability section are specified in the current draft of the standard. A few minority comments were received suggesting that the Applicability section proposed should either be expanded or reduced. The SDT believes industry supports the current draft of the proposed applicability.

The GVSDT did not propose a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section. This was discussed in relation to the proposed MOD-026-1 where a Planning Coordinator may request information on an excitation control system model for a technically justified unit. The GVSDT does not believe that it is likely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit, and governor response is not consistent from one frequency excursion event to the next. Stakeholders were asked if they agreed with this approach. The majority of industry comments support the GVSDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. There is minority opinion suggesting that such a Requirement should be developed; with some commenters also questioning the basis for the Applicability section and the capacity factor philosophy. Most of the minority comments were received from one Reliability Region and as such the GVSDT suggests that region should consider developing a

[1] The appeals process is in the Standard Processes Manual:
http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

Regional Standard containing a more stringent Applicability. The Planning Coordinator can still request a model review however, the review is not mandatory under the standard requirements.

Based on industry comments received, the following modifications to the proposed standard have been made by the GVSDT:

1) Corrections of various typos in the body of the standard, the VSLs, and in Attachment 1

2) Extended the time to comply with Requirement 1 from 30 to 90 days

3) Modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base loaded unit is considered verified).

4) Modified Attachment 1 (Periodicity Table) to clarify establishing the Initial Ten Year Unit Verification Period Start Date

5) Reduced the maximum time allowed between capture of an event and completing model verification from two years to one year.

6) Referenced the NERC GADS document for references to capacity factor in the draft standard.

7) Included partial load rejection as a potential test to obtain a recording of the equipment response to be used in model verification.

Index to Questions, Comments, and Responses

1. The Applicability section of MOD-027 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability? 14
2. Because it is not likely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit, and because governor response is not consistent from one frequency excursion event to the next, the SDT is not proposing a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section. Do you agree with the proposal to not include a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section? 22
3. The SDT discussed if MOD-027-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR. Do you agree with the proposal to not include the verification of synchronous condensers in MOD-027-1? 31
4. Are you aware of any regional variances that would be required as a result of MOD-027-1? If yes, please identify the regional variance. 38
5. Are you aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? 44
6. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain 51

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council , LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11. Chantel Haswell	FPL Group, Inc.	NPCC	5
12. David Kiguel	Hydro One Networks Inc.	NPCC	1
13. Michael R. Lombardi	Northeast Utilities	NPCC	1
14. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15. Bruce Metruck	New York Power Authority	NPCC	6
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17. Robert Pellegrini	The United Illuminating Company	NPCC	1
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19. Saurabh Saksena	National Grid	NPCC	1
20. Michael Schiavone	National Grid	NPCC	1
21. Wayne Sipperly	New York Power Authority	NPCC	5
22. Donald Weaver	New Brunswick System Operator	NPCC	2
23. Ben Wu	Orange and Rockland Utilities	NPCC	1
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

3.	Group	Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tino Zaragoza	IID	WECC	1
2. Sammy Alcaraz	IID	WECC	3
3. Diana Torres	IID	WECC	4
4. Marcela Caballero	IID	WECC	5
5. Cathy Bretz	IID	WECC	6

4.	Group	Albert DiCaprio	IRC Standards Review Committee (joint comments)		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Terry Bilke	MISO	RFC	2
2. Patrick Brown	PJM	RFC	2
3. Ben Li	IESO	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

4. Mark Thompson	AESO	WECC	2
5. Steve Myers	ERCOT	ERCOT	2

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	David Thorne	Pepco Holdings Inc Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Carl Kinsley	Pepco Holdings Inc	RFC	1, 3
2. Alivan Depew	Pepco Holdings Inc	RFC	1, 3

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jonathan Sykes, Chair	NERC System Protection and Control Subcommittee	X			X	X					X

No additional members listed.

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Carol Gerou	Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Power Dist	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Copperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
10.	Joseph DePoorter	Madison Gas and Electric Company	MRO	3, 4, 5, 6
11.	Scott Nichols	Rochester Public Utilities	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
13.	Richard Burt	Minnkota Power Cooperative	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

14.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
15.	Scott Bos	Muscatine Power and Water	MRO	3, 4, 5, 6
16.	Lee Kittleson	Otter Tail Power Company	MRO	5, 1, 3, 6
17.	Marie Knox	Midwest ISO	MRO	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jonathan Hayes	SPP Reliability Standards Development Team										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Reynolds	Sunflower Electric Power Corporation	SPP	1
2.	Valerie Pinamonti	AEP	SPP	1, 3, 5
3.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
5.	Louis Guidry	CLECO	SPP	1, 3, 5
6.	Sean Simpson	McPhearson Board of Public Utilities	SPP	1, 3, 5
7.	Robert Rhodes	SPP	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Co.	SERC	1
2.	James Manning	NC Electric Membership Corp.	SERC	1
3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1
4.	Pat Huntley	SERC Reliability Corp.	SERC	10
5.	Bob Jones	Southern Company Services	SERC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Tim Brown	Idaho Power-Power Production					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Guy Colpron	Idaho Power	WECC	5
2.	Mark Pfeifer	Idaho Power	WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Phil Pierce	Santee Cooper	SERC	5
3.	Paul Camilletti	Santee Cooper	SERC	5
4.	Rene Free	Santee Cooper		1
5.	Tom Curtis	Santee Cooper	SERC	5

				1	2	3	4	5	6	7	8	9	10
12.	Group	Annette Bannon	PPL Generation					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Leland McMillan	PPL Montana, LLC	WECC	5
2.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
3.		PPL Brunner Island, LLC	RFC	5
4.		PPL Holtwood, LLC	RFC	5
5.		PPL Martins Creek, LLC	RFC	5
6.		PPL Montour, LLC	RFC	5

				1	2	3	4	5	6	7	8	9	10
13.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		MRO	5, 6
2.	Connie Lowe		SERC	5, 6
3.	Michael Gildea		RFC	5, 6
4.	Larry Whanger		SERC	5
5.	Mike Crowley		SERC	1, 3
6.	Jeff Bailey		MRO	5

				1	2	3	4	5	6	7	8	9	10
14.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Baznik	FE	RFC	1
2.	Bill Duge	FE	RFC	5
3.	Brian Orians	FE	RFC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Joe Spencer - SERC Bob Jones - DRS chair	SERC Dynamics Review Sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Mallory Huggins	NERC Staff										

No additional members listed.

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Brown	PSE&G	RFC	1, 3
2.	Clint Bogan	PSEG Fossil	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
3.	Peter Dolan	PSEG ER&T	RFC	6
4.	Scott Slickers	PSEG Fossil	NPCC	5
5.	Eric Schmidt	PSEG ER&T	NPCC	6
6.	Mikhail Falkovich	PSEG Fossil	ERCOT	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Joe Spencer - SERC staff	SERC Generation sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Jason Marshall	ACES Power Members						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Jones	AEPCO/SWTC	WECC	1, 3, 5
2.	Mohan Sachdeva	Buckeye Power	RFC	4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
21.	Individual	Bo Jones	Westar Energy	X		X		X	X				
22.	Individual	Antonio Grayson	Southern Company					X					
23.	Individual	David Thompson	Tennessee Valley Authority GO					X					
24.	Individual	David Youngblood	Luminant Power					X					
25.	Individual	David Miller	Lakeland Electric	X									
26.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
29.	Individual	Edward Cambridge	APS	X		X		X					
30.	Individual	Brad Haralson	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
32.	Individual	Greg Campoli	New York Independent System Operator		X								
33.	Individual	Samuel Reed	Tri-State Generation and Transmission, In.	X				X					
34.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
36.	Individual	Mace Hunter	Lakeland Electric	X		X		X					
37.	Individual	John Bee	Exelon	X		X		X					
38.	Individual	Michael Goggin	American Wind Energy Association								X		
39.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
40.	Individual	Bob Casey	Georgia Transmission Corporation	X									
41.	Individual	Jeanie Doty	Austin Energy					X					
42.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
43.	Individual	Michael Brytowski	Great River Energy	X		X		X					
44.	Individual	Vladimir Stanisic	BC Hydro	X	X	X		X					
45.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
46.	Individual	Amir Hammad	Constellation Power Generation					X					
47.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
48.	Individual	Thad Ness	American Electric Power	X		X		X	X				
49.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
50.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
51.	Individual	Gary Chmiel	GE Energy										
52.	Individual	Kathleen Goodman	ISO New England		X								
53.	Individual	Dan Hansen	GenOn Energy					X					
54.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
55.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
56.	Individual	Eric Ruskamp	Lincoln Electric System	X		X		X	X				
57.	Individual	Jose H Escamilla	CPS Energy			X							
58.	Individual	Michael Falvo	Independent Electricity System Operator		X								
59.	Individual	Karen Alford	Gainesville Regional Utilities	X		X		X					
60.	Individual	Kirit Shah	Ameren	X		X		X	X				
61.	Individual	Rex Roehl	Indeck Energy Services					X					
62.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
63.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
64.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
65.	Individual	John Yale	Chelan County PUD	X				X	X				

1. **The Applicability section of MOD-027 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability?**

Summary Consideration: The vast majority of industry agrees that all generation configurations/types that should be included in the Applicability section are specified in the current draft of the standard. There was some confusion regarding the treatment of small units at plants. The SDT in response revised the Applicability to include plants greater than X MVA that have units with ratings less than 20 MVA (X is 100 for Eastern and Qubec, 75 for WECC, and 75 for ERCOT). The SDT believes that this revised applicability Section language is clearer while at the same time it still captures the appropriate units and plants for model verification (i.e., greater than 80% of interconnected VER plants for each Interconnection). A few minority comments were received suggesting that the Applicability section proposed should either be expanded or reduced. The SDT believes industry supports the current draft of the Applicability section proposed.

Organization	Yes or No	Question 1 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	

Organization	Yes or No	Question 1 Comment
SPP Reliability Standards Development Team	No	By setting the MVA rating at 100MVA in section 4.2.1 for single units aren't you excluding units? It is then mentioned in the bullet below that units below 20MVA are included but as an aggregate if the site is over 100MVA. We aren't clear how this is expanding the standard. The other standards in this group refer to the limits used in the Compliance Registry. Should this be consistent with those?
Response: Thank you for your comment. The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent. Also, the SDT revised the Applicability to include plants greater than X MVA that have units with ratings less than 20 MVA (X is 100 for Eastern and Quebec, 75 for WECC, and 75 for ERCOT). Note that "X" is 100 for the Eastern and Quebec Interconnections, 75 for WECC and ERCOT. The SDT believes that this revised applicability Section language is clearer while at the same time capturing the appropriate units and plants for model verification (i.e., greater than 80% of interconnected VER plants for each Interconnection).		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	We believe Black Start units, regardless of size, should be considered in this standard.
Response: Thank you for your comment. Turbine/Governor and Load Control or Active Power/Frequency Control models are less important for a black start unit emergency power source because these units are not typically modeled in planning studies. When needed, these units are started in asynchronous mode to power black start unit auxiliaries and are not configured to control grid frequency.		
Santee Cooper		
PPL Generation	No	
Dominion	No	
FirstEnergy	No	

Organization	Yes or No	Question 1 Comment
SERC Dynamics Review Sub-committee	No	The DRS agrees that the intended generating units would be covered by reasonable interpretation of the applicability section 4.2. However, the DRS recommends that footnote 3 be changed to read “The common transmission voltage level bus (i.e. 100 kV or greater) to which the step up transformer(s) is connected.” This more clearly includes “step up” transformers for some types of variable energy plants which may not be “generator step up” transformers.
Response: Thank you for your comment. The SDT agrees and has removed the footnote and revised the applicability for clarity.		
NERC Staff	No	We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
Response: Thank you for your comment. The SDT believes that the Applicability section is technology neutral.		
Public Service Enterprise Group	No	
SERC Generation sub-committee		
ACES Power Members	No	
Arizona Public Service Company	Yes	
Westar Energy	No	We suggest for consistency with the other standards in this project that this standard also reference the limits used in the Compliance Registry.
Response: Thank you for your comment. The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.		
Southern Company	No	1) We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time

Organization	Yes or No	Question 1 Comment
		frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action. 2) It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy.
Response: Thank you for your comment. The SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency such as a significant number of wind plants. For the Eastern Interconnection, 20 MVA rated units only have to be verified if they are part of a plant that is 100 MVA or greater. The SDT believes that 100 MVA plants in the Eastern Interconnection are significant. Also, the unit Applicability for this standard is already a subset of the Compliance Registry.		
Tennessee Valley Authority GO	No	
Luminant Power	No	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System		

Organization	Yes or No	Question 1 Comment
Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon		
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	

Organization	Yes or No	Question 1 Comment
Constellation Power Generation	No	No. CPG believes that the use of capacity factor, a variable data point, in the applicability of a standard is too problematic. Capacity factor is a market a function that is dependent on many variables outside of reliability and therefore does not belong in a reliability standard. CPG is also unsure as to how the SDT arrived at the MVA thresholds in each of the Interconnections, and is requesting that a technical justification of those thresholds be submitted along with the response of comments.
Response: Thank you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, units with a capacity factor of less than 5% are excluded from model verification however other standards still require that the data be supplied. The SDT believes it is not necessary to require all units in the compliance registry to have models verified. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent. Please note the calculation of capacity factor is specified in Appendix F of the GADS Data Reporting Instructions on the NERC website.		
Consolidated Edison Co. of NY, Inc.	No	
American Electric Power	No	
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
GE Energy		

Organization	Yes or No	Question 1 Comment
ISO New England	Yes	Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? This applicability criteria in this standard should be the same as the Compliance Registry requirements.
Response: Thank you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, units with a capacity factor of less than 5% are excluded from model verification however other standards still require that the data be supplied. The SDT believes it is not necessary to require all units in the compliance registry to have models verified. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.		
GenOn Energy	No	
Manitoba Hydro	No	
Duke Energy	No	We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action.
Response: Thank you for your comment. The SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units		

Organization	Yes or No	Question 1 Comment
that cannot control frequency, which includes a significant number of wind plants.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	No, we are not aware of any, but the Applicability Section of the draft standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the “generating units” suffice to generally include all types of energy resources?
Response: Thank you for your comment. The SDT is developing a technology neutral standard that covers all current and future technologies.		
Gainesville Regional Utilities	No	
Ameren	No	
Indeck Energy Services		
Oncor Electric Delivery Company LLC	No	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

2. Because it is not likely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit, and because governor response is not consistent from one frequency excursion event to the next, the SDT is not proposing a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section.

Do you agree with the proposal to not include a Requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section?

Summary Consideration: The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. There is minority opinion suggesting that such a Requirement should be developed; with some commenters also questioning the basis for the Applicability section and the capacity factor philosophy. Most of the minority comments were received from one Reliability Region and as such that region should consider developing a Regional standard containing a more stringent Applicability. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.

Organization	Yes or No	Question 2 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.		

Organization	Yes or No	Question 2 Comment
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	We agree with this proposal as being in line with our overall concern that model verification requirements should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
Response: Thank you for your comment. The SDT agrees and believes that it has implemented this philosophy in the draft of the standard.		
SPP Reliability Standards Development Team		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	Yes	
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee	Yes	
NERC Staff	No	The standard should include a requirement that provides the Planning Coordinator the ability to request a review of any turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section. Accurate turbine-governor models can be critical to valid underfrequency load shedding assessments and other studies requiring accurate frequency response. This is particularly important for large units that operate infrequently, but are committed for critical operating conditions such as peak load or other times of capacity deficiency.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements. Also, studies in support of the FR SDT effort show that governor response to a frequency excursion is a more critical concern during off peak operations when low capacity factor units are not expected to be committed. The reason for this is that during peak periods, there is inherently more inertia that helps mitigate the severity and duration of the generation – load mismatch.		
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 2 Comment
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 2 Comment
Lakeland Electric		
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.		

Organization	Yes or No	Question 2 Comment
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	No	A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. The Planning Coordinator can still request a model review however the review is not mandatory by standard requirements.		
American Electric Power	Yes	
Ingleside Cogeneration LP	Yes	MOD-027-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES frequency response - and have already the recording equipment needed to validate performance.
Response: Thank you for your comment. It is undesirable to link this standard with the DME standard development. Also, the DME standard applies to fault recorders and PMU equipment. Lower resolution data is adequate for this verification. We agree that if DME is already in place, then it should be simpler to capture the required data for verification. The applicability section requires verification of units larger than the threshold gross nameplate rating size specified for each interconnection and is intended to emphasize the importance of modeling critical units.		
Wisconsin Public Service Corp	Yes	We agree with this proposal as being in line with our overall concern that model verification requirements

Organization	Yes or No	Question 2 Comment
		should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
Response: Thank you for your comment.		
GE Energy		
ISO New England	No	NERC is largely concerned with the declining frequency response of the Eastern Interconnection and this proposal seems completely at odds with that concern. The Planning Coordinator (or Transmission Planner) should definitely be allowed to request verification of selected governors. In addition to generators that have governor effect overridden by outer control loops (Distributed Control System, DCS) there may be a dead band within the governor. The Transmission Planner must be able to request verification of selected governor models that may fall outside of the standard. The question mentions Planning Coordinator but the standard itself is applicable to the Transmission Planner.
Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. Both the Planning Coordinator and the Transmission Planner can still request a model review however the review is not mandatory by standard requirements. **It is true that the Planning Coordinator is not an applicable FME in the standard since the Planning Coordinator is not assigned responsibility for any of the Requirements.** **The SDT recognizes that modeling improvements are needed in the Eastern Interconnection to correctly represent the frequency response. This standard will require verification of the frequency response model for at least 80% of the interconnection MVA, which will result in improved modeling. The purpose of the standard is to improve the modeling of the frequency response. Other standards are responsible for improving the frequency response.**		

Organization	Yes or No	Question 2 Comment
GenOn Energy	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	We do not agree with this approach. Currently, the applicability threshold of nameplate rating greater that 100MVA is too high. The combined performance of many units smaller than the threshold identified in the applicability section will have a material effect on the system frequency response. Even if the standard leads to the provision of useable model to the Transmission Planner for the applicable generating units, without sufficient good models, it might not be possible to meet the goals of accurately represent generating unit active power response to system frequency variations and predicting system frequency response to contingencies.We repeat the concern we expressed in our comments to MOD-025-2 related to the applicability criteria “connected at the point of interconnection at greater than 100 kV.” This condition will lead to the exclusion of units that are material in dynamic simulations and to which the applicability should extend.Also, we wonder whether the inclusion of Planning Coordinator in the question is a typo or the standard is missing the Planning Coordinator as an applicable entity. Please clarify.

Response: Thank you for your comment. The majority of industry comments support the SDT proposal not to include a Requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. Governor response is not consistent from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc. Therefore, the SDT does not believe it is appropriate to include such a Requirement in MOD-027-1. Both the Planning Coordinator and the Transmission Planner can still request a model review however the review is not mandatory by standard requirements.

The SDT recognizes that modeling improvements are needed in the Eastern Interconnection to correctly represent the frequency response. This standard will require verification of the frequency response model for at least 80% of the interconnection MVA, which will result in improved modeling. The purpose

Organization	Yes or No	Question 2 Comment
of the standard is to improve the modeling of the frequency response. Other standards are responsible for improving the frequency response. It is true that the Planning Coordinator is not an applicable FME in the standard since the Planning Coordinator is not assigned responsibility for any of the Requirements.		
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indeck Energy Services	Yes	
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

3. The SDT discussed if MOD-027-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR.

Do you agree with the proposal to not include the verification of synchronous condensers in MOD-027-1?

Summary Consideration: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.

Organization	Yes or No	Question 3 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	Can’t generators be operated as synchronous condensers if needed?
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards	No	It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.

Organization	Yes or No	Question 3 Comment
Review Forum (NSRF)		
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
SPP Reliability Standards Development Team	Yes	We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee	Yes	We agree that it shouldn't be included. However, it appears that there is an error in the question. Synchronous condensers cannot be used to control frequency. Was this a "cut and paste" error from MOD-026?
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
NERC Staff	Yes	We agree that it is not necessary to validate synchronous condenser models in MOD-027 since synchronous

Organization	Yes or No	Question 3 Comment
		condensers do not provide frequency response. However, the discussion supporting this question refers to verification of excitation control systems. Validation of synchronous condenser excitation control systems should be required in MOD-026.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error. The topic of synchronous condensers being included, or not, in the Applicability section of MOD-026 will be addressed in the standards process for MOD-026.		
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	No	
Westar Energy	Yes	
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 3 Comment
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	condensers have no effect on system frequency, they are there for voltage support. We agree they should not be in MOD-027-1.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Lakeland Electric		
Exelon		
American Wind Energy Association	Yes	
Tacoma Power		
Georgia Transmission	Yes	

Organization	Yes or No	Question 3 Comment
Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro		This standard would not apply to SCs in any case
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Northeast Utilities	No	Can't generators be operated as synchronous condensers if needed?
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	No	Can't generators be operated as synchronous condensers if needed?
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
American Electric Power	Yes	Synchronous condensers respond to changes in voltage and not frequency, and as a result, have no place within the scope of this standard.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	Yes	There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Wisconsin Public Service Corp	Yes	It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
GE Energy		
ISO New England	Yes	
GenOn Energy		
Manitoba Hydro	Yes	-MOD-027-1 cannot be applicable to units dedicated as synchronous condensers since such units do not have turbine/governor and load control or active power/frequency control functionality installed. For generator units which can be operated as synchronou
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Duke Energy	Yes	Not sure why this question is in the CF, other than it was accidently copied from the MOD-26 CF? Synchronous condendors are MVAR devices not MW devices and thus should be covered by MOD-26, not 27, if their dynamic response is signficant to grid reliability. Since they are typically applied in weak spots of the transmission system, it's difficult to believe they would not be critical by their presence.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Lincoln Electric System		

Organization	Yes or No	Question 3 Comment
CPS Energy		
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	The question does not appear to be worded correctly. Draft Standard MOD-027-1 deals with turbine/governor and load control, rather than excitation control systems.
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Indeck Energy Services	Yes	
Oncor Electric Delivery Company LLC	No	Oncor does not believe that the inclusion of dynamic reactive devices such as SVC's should be included in MOD-027-1
Response: This question was not intended to be on the Comment Form. The SDT recognizes that synchronous condensers do not contain frequency control elements and regrets the administrative error.		
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

4. Are you aware of any regional variances that would be required as a result of MOD-027-1? If yes, please identify the regional variance.

Summary Consideration: The vast majority of industry comments did not identify any regional variances. There are minority comments concerned with development of Regional standards. The SDT believes that a Regional standard will have to align with the requirements of a national standard. The SDT also believes that the current Applicability section threshold, which corresponds to greater than 80% of the connected unit MVA per Interconnection, does not constitute a regional variance.

Organization	Yes or No	Question 4 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	No	

Organization	Yes or No	Question 4 Comment
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	No	
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
Public Service Enterprise Group	No	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	No	Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Response: Thank you for your comment. The SDT suspects this comment was intended for another standard. However, for the Western Interconnection, Units that are rated 20 MVA only have to be verified if they are part of a plant that is 75 MVA or greater. The SDT believes that 75 MVA plants in the Western Interconnection are significant.		

Organization	Yes or No	Question 4 Comment
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	Yes	We think it is possible that the unit rating which is critical to the BES may vary from region to region.
Response: Thank you for your comment. The SDT believes that it has accounted for units that are critical to the control of frequency by establishing interconnection specific MVA thresholds corresponding to 80% or greater of the installed MVA generation capacity.		
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	

Organization	Yes or No	Question 4 Comment
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	No	

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP is not aware of the need for any regional variances that might be required as a result of MOD-027-1.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	Yes	In the TRE region, there is already a generator governor/frequency response standard under development. It is not obvious to us that the TRE standard aligns with MOD-027-1.
Response: Thank you for your comment. It should be recognized that a Regional standard also has to comply with the requirements of a National standard.		
Wisconsin Public Service Corp	No	
GE Energy		
ISO New England	No	
GenOn Energy		
Manitoba Hydro	No	
Duke Energy	No	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren		

Organization	Yes or No	Question 4 Comment
Indeck Energy Services	Yes	The standard as drafted contains regional standards (ERCOT vs WECC). The ROP doesn't permit members of one region to vote on regional requirements for other regions. Regional standards will be required to implement regional differences.
Response: Thank you for your comment. The SDT believes that it has accounted for units that are critical to the control of frequency by establishing interconnection specific MVA thresholds corresponding to 80% or greater of the installed MVA generation capacity. Even though the MVA threshold is different for each Interconnection, the penetration of connected MVA is essentially the same. It should be recognized that a Regional standard also have to comply with the requirements of a National standard.		
Oncor Electric Delivery Company LLC	Yes	Oncor is in general agreement of the standards however, Oncor believes that the Transmission Planner in the ERCOT Region is not the appropriate receiving entity of test verification data from the Generator Owner. Oncor believes that a regional variance should be given strong consideration such that the Planning Authority would be the receiving entity of all testing data from the Generator Owner. This would align with current ERCOT protocols, operating guide and planning guide at it relates to resource testing and verification.
Response: Thank you for your comment. The SDT believes that it is appropriate to make the Transmission Planner responsible. The Transmission Planner can delegate work as appropriate.		
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

5. Are you aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration: The vast majority of industry comments did not identify any conflict between the proposed MOD-027-1 standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement. There are minority comments concerned with the development of Regional standards and also the compatibility of the standard with rules of procedure, LGIAs, etc. The SDT believes that a Regional standard and rules of procedure will have to align with the requirements of a national standard.

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	No	

Organization	Yes or No	Question 5 Comment
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	
Santee Cooper		
PPL Generation	No	
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee	No	
NERC Staff	No	
Public Service Enterprise Group	No	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	Yes	
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	No	

Organization	Yes or No	Question 5 Comment
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	Yes	The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency

Organization	Yes or No	Question 5 Comment
		deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that "Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units…".
Response: Thank you for your comment. The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode.		
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation	No	
Austin Energy	No	ERCOT has been performing computer modeling based on RARF data provided by GO's.
Response: Thank you for your comment.		
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	

Organization	Yes or No	Question 5 Comment
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	No	
American Electric Power	No	AEP is not aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp	No	
GE Energy	No	
ISO New England	Yes	Requirement R4 is a direct violation of the Large Generator Interconnection portion of the ISO Tariff that requires generators to request permission and provide models prior to making changes to the equipment characteristics. As currently written, this appears to allow generators to submit models after making the changes. Such changes may have been detrimental to system performance and therefore need to be reviewed prior to implementation.
Response: Thank you for your comment. This standard does not preclude the Transmission entity from requiring a model specified by an Interconnection Agreement or other local grid codes. Requirement R4 is a verification requirement therefore verification cannot occur until after frequency control equipment changes are implemented.		
GenOn Energy	No	
Manitoba Hydro	Yes	A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities

Organization	Yes or No	Question 5 Comment
		are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
Response: Thank you for your comment. The definition of BES and the Applicability in the standard do not have to align. The proposed Effective Date in both the Implementation Plan and in Section 5 of the standard takes into account the differences between US and Canadian entities.		
Duke Energy	No	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren		
Indeck Energy Services	Yes	Regional differences violate the ROP.
Response: Thank you for your comment.		
Oncor Electric Delivery Company LLC	Yes	Sections 3.2.1 and 3.2.2 of the ERCOT Operating Guides direct resource entities to communicate operating capabilities directly to the ERCOT ISO. The ERCOT ISO is registered as the Planning Authority. Section 3.3 of the ERCOT Operating Guides direct resource entities to communicate changes to operating capabilities to the ERCOT ISO. Various resource test requirements as listed in Section 8 of the ERCOT Operating Guides indicate data submissions to the ERCOT ISO.
Response: Thank you for your comment. The SDT believes that it is appropriate to make the Transmission Planner responsible. The Transmission Planner can delegate work as appropriate.		

Organization	Yes or No	Question 5 Comment
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

6. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain.

Summary Consideration: Based in part on industry comments received to this question, the following modifications to the proposed standard have been made by the SDT. (note: some of these issues and listed modifications are addressed by other consideration of comments questions):

1) Corrections of various typos in the body of the standard, the VSLs, and in Attachment 1
2) Extended the time to comply with Requirement 1 from 30 to 90 days
3) Modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base loaded unit is considered verified).
4) Modified Attachment 1 (Periodicity Table) to clarify establishing the Initial Ten Year Unit Verification Period Start Date
5) Reduced the maximum time allowed between capture of an event and completing model verification from two years to one year.
6) Referenced the NERC GADS document for references to capacity factor in the draft standard.
7) Included partial load rejection as a potential test to obtain a recording of the equipment response to be used in model verification.

Organization	Yes or No	Question 6 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
Response: Thank you for your comment. The SDT believes that the proposed applicability thresholds will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the		

Organization	Yes or No	Question 6 Comment
Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.		
Imperial Irrigation District (IID)	Yes	IT WOULD BE EFFECTIVE IF SDT WOULD CONSIDER PROVIDING A DETAILED EXAMPLE OF DYNAMIC MODELS, GRAPHS, AND INFORMATION REQUIRED AS PART OF THIS STANDARD.
Response: Thank you for your comment. This standard is not a guideline for developing model parameters. The standard describes what should be done and specifically is not perscriptive. The SDT recognizes expertise is needed to perform model verification for specific types of equipment.		
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	Please consider the following comments:Footnote 2 - Include the explanation that “average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value”, since historically some have asked how this factor is defined and calculated”.Requirement R3, bullet 2 - Append wording like, “such as a model is unusable by the Transmission Planner, dubious model type, abnormal model parameter values, and unusual simulation results” to the text, “technical concerns with the verification documentation”. Attachment 1, Row 6 (New or Existing Generator Unit) -Replace “Excitation control system model” with “Turbine/governor and load control or active/frequency control system model”. Comments: We have a number of questions and concerns as follows: o While the Standard uses the word “verified” and “verification” loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-

Organization	Yes or No	Question 6 Comment
		band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. o If a simulation study results in response characteristics that does not match an on-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Response: Thank you for your comment. In response to this and other industry comments, the SDT has referenced the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions on the NERC website. **Regarding the rest of your comments, the SDT offers the following response:** **The SDT constructed text language to ensure the Transmission Planner can address any technical concern with the Generator Owner. Since the Generator Owner is responsible for the model, the Generator Owner can respond that the technical concern raised is unfounded.** **The SDT regrets the Attachment 1 typographical error and will correct.** **The turbine/governor and load control or active power/frequency control response is a characteristic of the generator equipment, not the external system. The intent is that the Generator Owner should strive to match the predicted response of the complete model with the actual response recorded. Verification of individual parameters should not be the emphasis of the model verification effort.**		

Organization	Yes or No	Question 6 Comment
It is true that modifying a parameter will alter the predicted response of the model however, an individual parameter should not be assigned an incorrect value for the sake of verifying the model. Ideally, model parameters should be altered to more accurately reflect the physical characteristic represented. However, based on actual experience in the WECC region, the ultimate goal of the verification process is to sufficiently refine model parameters to consistently approximate equipment response to a frequency excursion. The SDT recognizes expertise is required to perform model verification and this is the reason why the model verification periodicity proposed is a 10 year cycle. **Especially considering that the units contained in the Applicability is a subset of the NERC Compliance Registry, the SDT believes that the drafted standard is cost efficient to the industry. As a basis, the SDT recognized that the governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in improved accuracy of the governor model used in dynamic simulation. Utilizing engineering judgment, based in part on recent entity experience with verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA in each Interconnection. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.**		
SPP Reliability Standards Development Team	Yes	In the VSLS for R2 there is a “no” that needs to be deleted. In VSLS for R2 and R4 there is a footnote referenced on page 2 of the draft standard so it shouldn’t be included here as well.
Response: Thank you for your comment. The SDT believes that it has made the corrections you noted. Please review the current draft of the standard to make sure your concern was addressed.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		WECC has an existing model validation policy that is well defined and established. This project documentation does not specifically state that MOD-012 and MOD-013 would be retired. If not, this policy would be redundant with the existing WECC policy.
Response: Thank you for your comment. MOD-027 is a verification requirement. MOD-012 and MOD-013 are data submittal requirements. There are no plans to retire MOD-012 and MOD-013.		
Santee Cooper		

Organization	Yes or No	Question 6 Comment
PPL Generation	Yes	PPL Generation suggests the following changes:1. Increase the capacity factor threshold identified in the Applicability Section from the current 5% to 10%. Otherwise, ambient monitoring may be required for an excessively long period.2. Allow the use of OEM-provided governor models and, if adequate, existing models to satisfy the requirement in R2. OEM models can have equivalent-or-better validity than on-line testing.3. Define what response is expected to be documented for Requirement 2.1.1 (as pertaining to a time-frame of 30 seconds or less, and to sudden frequency dips, not step-increases). Units have an immediate response (e.g. opening the control valves) and a long-term response (e.g. ramping-up the coal feed). Governors (the subject of this standard) deal only with the former category. Ambient monitoring should eventually provide a frequency-dip event to analyze, but the same is not true for opposite-direction events.4. Should the recorded response in Requirement 2.1.1 be the predicted response? It appears that the on-line response and the recorded response are the same thing.5. In Requirement 2.1.1, clarify under what circumstances a lack of response constitutes suitable verification, e.g. experiencing a frequency drop for units running valves-wide-open or CTGs at baseload firing temperature.

Response: Thank you for your comment. Q1: The SDT believes that the 5% capacity factor threshold functions to establish a balance between verifying modeling information for units that play an important role in the reliability of the BES and units that report information which is not verified because they are seldom online and have a relatively diminished reliability role. While it is true that units that have a capacity factor that is marginally greater than 5% could result in a long ambient monitoring period before capturing a response suitable for model verification, the SDT believes that it is better to wait for a suitable event as opposed to requiring a on-line staged test that Generator Owners are not comfortable performing and even argue is not an accurate test. However, in part due to recognizing that relatively low capacity factor units (though greater than 5%), the SDT has added to the standard the ability of the Generator Owner to perform a partial load rejection test. As with the reference change test, the partial load rejection test is an optional strategy. The Generator Owner can choose to wait on an ambient event when the unit is in a mode that is expected to be able to respond to the frequency excursion. Also, as noted in an added footnote in the current draft of the standard, differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on load data under the normal operating conditions under which the model is expected to apply

Q2: OEM models are not verified and do not capture potential load control or MW setpoint functions.

Q3: Please reference modification of 2.1.1 that clarifies the SDT intent of comparing predicted model response to actual equipment response. The SDT did not specify the timeframe for model verification, instead leaving it to the expert performing model verification to establish. The standard is constructed such that either an over frequency or under frequency event is allowed to be used for model verification. The SDT believes the industry understands that model

Organization	Yes or No	Question 6 Comment
validity during normal stability studies is less than 30 seconds. **Q4 The SDT has modified Requirement 2.1.1 in response to your comment.** **Q5: The SDT has modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base loaded unit is considered verified).**		
Dominion	Yes	While we understand that a significant portion of the industry supports the 5% capacity factor threshold, we believe that this term is subject to different uses by various entities and parties, particularly biased as to whether one is discussing capacity or energy. We suggest that, for the purpose of this standard, capacity factor be described as defined by NERC GADS.Please elaborate on Requirement 2.1.5. Also, we believe that “Load Control” and “AGC” are the same.R3, the third bullet, we suggest that “did not match the recorded response for three or more transmission system events be changed to “did not approximate the recorded response for three or more transmission system events “We believe there needs to be an exception allowed if a frequency event does not occur in 10 years.What is “staged test” mentioned on Attachment 1? Also Attachment 1 is very confusing and should be rewritten.
Response: Thank you for your comment. The SDT has incorporated your suggestion and updated footnote 2 by referring to the NERC GADS definition (Attachment F). **Load Control and AGC are not the same. Load Control is a plant control also known as MW control. AGC is a Balancing Authority level control.** **The SDT incorporated your recommendation for R3.** **Based on this and others comments, the SDT realized there was an omission in Attachment 1 (the Periodicity Table). Attachment 1 has been revised to make it clear that if a unit is not in a control mode with MW output responsive to a frequency excursion during the 10 year verification cycle, then the entity can continue to wait for this scenario to occur.** **The “staged test” mentioned in Attachment 1 is the “on-line frequency reference change” test referenced in 2.1.1. The SDT has made several corrections and modifications to Attachment 1 in an attempt to make the document easier to understand, including clarifying the Initial Ten Year Unit Verification Period. Also, the SDT has added to the standard the ability of the Generator Owner to perform a partial load rejection test. As with the reference change test, the partial load rejection test is an optional strategy. The Generator Owner can always wait for a frequency excursion to occur when the unit is in a mode that it would be expected to govern. Please review the revised version and provide additional feedback during the next posting.**		
FirstEnergy	Yes	As a result of the 2010 NERC Generator Governor Survey, it became clear that many nuclear units (and I

Organization	Yes or No	Question 6 Comment
		believe all of the BWR units) do not respond to changes grid frequency because their governors are controlling steam pressure. The standard should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that "Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units...". For those nuclear units that are able to respond to overfrequency events there is a possibility that a response to a system transient may not be seen during a ten year period. Since responding to an overfrequency event will result in a drop in unit load and a corresponding change in reactivity, the governor control dead band, which is set to minimize the possibility of a spurious reactivity change, could be large enough to ignore an event that meets the frequency excursion threshold (for example a 0.1 Hz dead band would ride through on a 0.07 Hz excursion). Likewise a nuclear unit would not perform a frequency reference change input test with the unit on-line because of the resulting change in reactivity. Would injecting a frequency signal to the EHC during off-line calibration and noting the response be acceptable?
Response: Thank you for your comment. The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode.		
SERC Dynamics Review Sub-committee	Yes	For Requirement R1, the SERC DRS recommends that the time be changed from 30 calendar days to 90 calendar days. Relative to the time allowed for accomplishing other requirements, there is no benefit for only allowing 30 days for requirement R1. 90 days would allow for more communications between the requesting Generator Owner, the providing Transmission Planner and other entities (such as the software vendor or turbine manufacturer) to coordinate obtaining the necessary items listed in requirement R1. Additionally, 90 days would be consistent with the "more than 90 days" VSL level for this requirement.Relative to R3, bullet three, this covers the situation where predicted response does not match recorded response for three or more events. We suggest this be one or more events because significant events are so rare in the eastern interconnection.Relative to the VSL for R2, the first paragraph in the "Severe column" has confusing words "failed to provide the verified models no more than 90 days late." We

Organization	Yes or No	Question 6 Comment
		recommend changing the words to "provided more than 90 days late".In multiple locations in Attachment 1, 730 days seems to be an excessive amount of time from capturing an event to sending documentation to the TP. We recommend a period of 180 days.In two places in Attachment 1, excitation control system is referred to. Shouldn't this be turbine/ governor control system?
Response: Thank you for your comment. The SDT corrected the discrepancy between R1 and the R1 Lower VSL by changing R1 language to read "within 90 calendar days". The SDT believes that the 0.05 hertz frequency deviation for the Eastern Interconnection will be exceeded often enough to verify consistent unit equipment response to frequency excursions. As an example, in October 2010, there were 12 Eastern Interconnection frequency excursions that exceeded 0.05 hertz. Based on this and other comments, the "Severe" VSL language for R2 has been revised. The SDT decided to modify periodicity to indicate that from the date of the last recorded frequency excursion response, the Generator Owner has one year to verify the model. It is expected that the Generator Owner will collect several frequency excursion responses however, the standard only requires model verification within one year of the frequency excursion collected for compliance within the 10 year timeframe. The Attachment 1 copy and paste errors with references to "excitation control systems" have been corrected.		
NERC Staff	Yes	It is not possible to accurately model system frequency response with valid models for only 80% of the installed system capacity. System frequency perturbations are experienced by and responded to by all frequency responsive generators, regardless of interconnection voltage. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per SDT estimates, this will assure accurate modeling for approximately 95% of installed capacity. The interconnection voltage is not relevant to frequency response and should not be a condition for applicability. We also disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions giving them lower capacity factors. However, those will also be the units loaded at lower levels, making them the units with head-room to respond, thereby making them critical to frequency response during those conditions. They may be of a lower priority in the implementation plan.The violation risk factors associated with Requirements R1 through R5 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits

Organization	Yes or No	Question 6 Comment
		of the system.The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R5 should include the operations planning horizon.In Requirement R2, part 2.1.1, it appears the comparison should be between recorded response and simulated modeled response rather than between on-line response and recorded response. Further clarification is necessary.In Requirement R4, when the turbine/governor and load control or active power/frequency control system are modified as part of a planned project, the Generator Owner should be required to provide a revised model prior to placing the revised equipment back in service.In Requirement R5, part 5.2, the reference to negligible transients is not measurable. We recommend modifying this to ". . . results in a response that varies less than the numerical stability of the program used for the simulation."In Requirement R5, part 5.3, the introductory phrase "For an otherwise stable simulation" is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with "A disturbance simulation results in . . ."The SDT should consider use of the word "verification" versus "validation" and assure that the term used in this standard is consistent with other standards.Validation of models only every 10 years is far too long a period. Models should be calibrated as often as possible, preferably with every significant system frequency disturbance. Experience in the WECC region has shown that validation by observation against system events yields more accurate model performance than relying on a single staged test because the events provide for a wide variety of system conditions for the comparison. The background material suggests that more frequent validation against frequency events is impractical because of the scarcity of events. That is incorrect; there are several frequency events each year in all of the interconnections where frequency deviates beyond the short-term trigger limits set forth by the Resources Subcommittee, which indicate that generators should have exceeded the traditional deadband of Â±36 mHz and responded. The initial completion of validation for all applicable units should be within 5 years, not 10 years. The 10 year time is excessive.Validation or calibration after a measured system event should occur within 6 to 9 months of the event, not 2 years. Experience in the WECC regions shows this to be sufficient and achievable.

Response: Although the standard does not require verification of modeled frequency response for all units/plants smaller than the MVA nameplate rating thresholds listed in the Applicability section, it is expected that provided models are accurate.

The SDT believes that requiring verification of small size MVA units and units with a small (< 5%) capacity factor is not practical and would deplete the industry's limited verification capability for very little reliability benefit as concluded from the field testing involving 4 regions (WECC, SERC, ERCOT, and the FRCC) initiated by the Phase III-IV SDT and completed July 2007. Units with low capacity factors would seldom be running during significant frequency

Organization	Yes or No	Question 6 Comment
events, and measurements of ambient response data needed for verification would be unavailable because the units were likely not running. With regard to the interconnection voltage identified, the standard does not deviate from the NERC registration requirement. The SDT believes that the 10 year period provides is adequate for both initial verification and re-verification given that the standard also specifies re-verification when equipment changes are made that would affect the units' frequency response. The SDT believes that the lower VRF is appropriate because the model is suppose to be accurate even if the model is not verified. The verification merely provides assurance that the model is accurate. Violation of these requirements are not expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system, which is consistent with the low risk level guideline established. As a comparison, MOD-10 and MOD-12 requirements specify providing a complete set of data for all entity facilities and/or generators. This typically will involve dozens if not hundreds of generators whereas MOD-027 requirements only specify providing data for a single generator unit. Because model verification act ivies typically take months if not years to perform, the time horizon of “Long Term Planning” is appropriate. The SDT thanks you for the comment regarding requirement R2 subpart 2.1.1. The standard has been corrected to require comparison between modeled and measured response. The SDT agrees that models should be revised when equipment is changed. The requirement for providing accurate models is specified by MOD-012. Verification cannot occur until after the revised equipment is in service. There is no known industry practice to take into account the numerical stability of the program. Also, it is left up to the judgment of the expert reviewing the study results to determine if the transients are negligible. Utilizing a stable simulation is necessary to determine if the model will adversely impact the robustness of dynamic modeling to be performed. If an unstable simulation is used as basis, then there is no way to determine additional negative response of the model that is being assessed for useability. The SDT agrees that the term verification is a better term for the requirements of this standard than validation. The standard as currently drafted uses the term verification, not validation. Also, the SDT does recognize that there are several frequency events each year which results in frequency deviations that would exceed traditional deadband settings. It was not the intention of the SDT to suggest otherwise. However, a unit must be both on-line and in a proper operating state so that meaningful MW response recordings can be collected. Regarding the 2 year time frame for validation after a measured system event is recorded, Attachment 1 has been revised to provide only a 1 year period after the event is recorded. This time period provides the Generator Owner time to be notified of the event and assess the impact. The SDT intent was to recognize that it would be a challenge in some Interconnections for a suitable frequency excursion to occur with the unit in a responsive operating state. Based on industry responses to both MOD-027 and MOD-026 postings, the SDT believes that the majority of industry agrees the proposed 10 year periodicity		

Organization	Yes or No	Question 6 Comment
verification cycle is appropriate.		
Public Service Enterprise Group	Yes	Nuclear units are often prohibited by their NRC licenses from having their governors engaged for frequency response. Since the Purpose of the standard is to "accurately represent generator unit real power response to system frequency," nuclear units with the restriction described above will have no response. These units should be explicitly exempted from the standard in the Applicability section.
Response: The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode.		
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	No	30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Response: Thank you for your comment. The SDT believes this comment was intended for another standard.		
Westar Energy	No	
Southern Company	Yes	1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don't match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future

Organization	Yes or No	Question 6 Comment
		model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) In Requirement R4, it is unclear how an entity could revise model data without performing a model verification - (the requirement is written to either revise model data or plan to perform model verification) 8) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. Those items that need correcting include: 8a) The "Facility" column entries need to better describe the conditions that are being detailed in the "Condition" column. Can some additional words better describe the each row? [for example, the row 2 could have the title 1-existing unit, no sister unit exceptions; row 3 could have the title 2-existing unit, sister unit exception applies, etc.] 8b) The use of "exceptions" in the Draft 1, row 2 is not defined and it is unclear what exceptions may apply. 8c) Can the third AND element of the Condition described in row 2 be written more simply by beginning "While the unit is operating in a frequency responsive mode and is subjected to at least one BES frequency excursion as specified in Criteria 1 above." This change could be used in multiple entries of this table to simply the reading and understanding. 8d) For row 3 (with exceptions row), we suggest eliminating the requirement for the same physical location being true for allow "sisterhood" - an entity is likely to own multiple units at different physical locations which are identical. 8e) Row 5 contains "new excitation control system equipment" - shouldn't this be "new governor/load control equipment"? 8f) Row 7 contains "Excitation control system model" rather than "Gov/Load control model"

Response: Thank you for your comment. 1) The SDT revised Requirement 2.1.1.

2) Based on this and other comments, the SDT lengthened the R1 time frame to 90 days to match the time frame in the associated VSL.

3) The SDT revised Severe VSL language for R2.

4) The SDT agrees the incorrect grammar and has incorporated language similar to what you suggested.

5) The SDT agrees and has incorporated suggested language.

6) The SDT agrees and has incorporated suggested language.

7) In most instances, verification of the model will be required instead of revising model data. An instance where revising model data can suffice is if MW set

Organization	Yes or No	Question 6 Comment
point control is implemented instead of droop control. **8) For 8a) and 8b) NERC has discouraged the use of the term "sister unit" and other folksy terms therefore the SDT believes current language is sufficient. For 8c) The SDT incorporated suggested language. For 8d) The SDT believes that the proxy unit philosophy should be limited to units at the same physical location to improve the likelihood of a legitimate inspection walkdown of equipment and settings is performed by the same individual ensuring that the units are actually "proxy " units. For 8e and 8f) The SDT regrets the copy and paste errors and has corrected them.**		
Tennessee Valley Authority GO	Yes	It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency excursion. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. 2)
Response: . Thank you for your comment. For the Eastern Interconnection, 20 MVA rated units only have to be verified if they are part of a plant that is 100 MVA or greater. The SDT believes that 100 MVA plants in the Eastern Interconnection are significant. Also, 20 MVA plants are included in the NERC Registry Criteria.		
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	Yes	Section 4.2 of proposed Standard MOD-027-1 provides that units or plants with an average capacity factor greater than 5% over the last three calendar years, that also meet other characteristics, will be considered "applicable units." However, the term "capacity factor" is not defined in proposed Standard MOD-027-1. Proposed Standard MOD-026-1, on the other hand, uses the term "Capacity Factor," suggesting it is a defined term but without an accompanying definition in the NERC Glossary of Terms or otherwise. PacifiCorp believes that the Standards Drafting Teams should make the use of the term "capacity factor" consistent across all proposed standards and define the term as necessary for additional clarity.
Response: Thank you for your comment. The SDT has addressed your suggestion and updated footnote 2 by referring to the NERC GADS definition of capacity factor, in both MOD-026 and MOD-027.		

Organization	Yes or No	Question 6 Comment
South Carolina Electric and Gas	Yes	How are sister units to be handled? Do they all need to be tested individually. Also, are all the units counted individually when calculating the percent of units in the implementation schedule?
Response: Thank you for your comment. Attachment 1 has been revised for clarity regarding the requirement as it pertains to equivalent (sister) units. In determining the percentage of fleet generating units satisfying verification requirements for each implementation schedule effective date specified, all equivalent units are counted as verified if Attachment 1 conditions specified for equivalent units are satisfied.		
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	1) Item 2.1.1 should be reworded: ".......model verification activities including the on-line RECORDED response compared to the MODEL'S SIMULATED response....."2) It is anticipated that many GO/GOP's may not have industry experience with modeling concepts and model verification techniques. It may be beneficial to provide an appendix for reference that basically describes the anticipated mechanics of how the verification is performed. This may help provide consistency for the verification process.
Response: Thank you for your comment. Requirement R2 subpart 2.1.1 language has been revised. The standard describes what should be done and specifically is not prescriptive. The SDT recognizes expertise is needed to perform model verification for specific types of equipment. Prior to developing the standard SAR, several entities in 4 NERC Regions field tested the concept and demonstrated that verification is practical. Also note that there is an extensive Reference section (Section G) listing several technical papers that address modeling techniques.		
Dynegy Inc.	Yes	1) In R2.1.1 it is not clear if the “recorded” response refers to the model response. Consider rewording this requirement to make clear the meaning of “recorded”. 2.) Attachment 1 seems to give two options for periodicity of verifying the model frequency control functions for existing generators. One option is to record data for a BES frequency excursion during a ten year calendar period. A second option is to record such data after the ten year period if a suitable BES frequency excursion does not occur. Does this mean existing generators can wait indefinitely for a suitable frequency excursion to verify the model response?
Response: Thank you for your comment. The wording in R2 subpart 2.1.1 has been revised. **2) Given the importance of verifying the model based upon actual performance while synchronized to the system, the standard is written to allow ample time for the generator to experience a suitable frequency excursion with the unit on-line and responsive. This means that a GO can wait longer than 10 years for a suitable frequency excursion with the unit on-line and in a mode that it is expected to governor. Also, within the 10 year recurring window, optional**		

Organization	Yes or No	Question 6 Comment
staged tests can be conducted (reference change test or partial load rejection test) in lieu of monitoring for an acceptable ambient event. Since industry has expressed concern, Attachment 1 has been revised to make clear generating units normally operated as a base loaded unit or with valves wide open do not need to be verified. Instead, a statement describing the units operating condition is sufficient for compliance with the requirement. Also, other elements of Attachment 1 have been revised for clarity, including establishing the Initial Ten Year Unit Verification Period.		
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	Yes	Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities.The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. As detailed in a memorandum from Jesus (Nano) Sierrra (FERC) to John Odom (ERAG Management Committee Chair), "Follow-up on the Provision of Primary Frequency Response by Nuclear Units in the ERAG-MMWG Dynamic Models," dated April 27, 2011, most all generating units do not respond to frequency deviations; however, there are some nuclear unit designs that do have limited response to under frequency conditions. It is important to note that even if a nuclear unit' s governor design does have limited response to grid frequency deviations, the nuclear unit is administratively restricted by their respective NRC operating license requirements to 100% thermal power. It is not clear from the proposed Standard MOD-027-1 or the Implementation Plan the SDT intended implementation timeline for the first verification period. That is, when must Requirement R2 be completed for the first 25% of the Generator Owner's applicable units? The second 25%? Etc. It is confusing when

Organization	Yes or No	Question 6 Comment
		considering the wording in Section A.5, "Effective Date:" combined with the wording in Attachment 1, Criteria 2 of the Standard. In addition, the Implementation Plan does not provide any further guidance.Is the intent that the staggered percentage implementation provides the start time for the generating units to complete R2 within a following ten year period? This would allow the applicable units to modify/install recording equipment and then set T=0 to then start the ten year staggered verification period.ORIs the intent to short cycle the initial verification period during implementation based on the percentage of units and then set up a ten year staggered verification period thereafter?
Response: Thank you for your comment. The SDT has added an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT believes this modification will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode **Regarding the rest of your comment, Attachment 1 has been revised for clarity and to better reflect the intent of the Implementation Plan. Attachment 1 Criteria 2 has been revised to incorporate the Implementation Plan 9-year transition period schedule including guidance for compliance.**		
American Wind Energy Association	No	
Tacoma Power	No	
Georgia Transmission Corporation	Yes	Have software manufacturers agreed to provide their models as described in R1?
Response: Thank you for your comment. Yes, the major software manufacturers have agreed to provide their models as described in R1. No later than by the effective date of the standard, software manufacturers' model information can be obtained from them by entering into the agreements they require.		
Austin Energy	Yes	Since dynamic data for old units is often not available, the SDT may consider allowing the use of typical or generic modeling parameters for these units.
Response: Thank you for your comment. If the unit is covered by the proposed Applicability of the draft standard, then the model can still be verified in		

Organization	Yes or No	Question 6 Comment
accordance with the Requirements specified. This is true even if existing dynamic data for an older unit (submitted per the submission Requirements of MOD-012 and MOD-013) is typical or generic data.		
Wisconsin Electric	Yes	It is not clear how this standard would be applied to wind generators. They should perhaps be specifically exempted from these requirements.
Response: Thank you for your comment. Some wind equipment have controls that can respond to a frequency excursion. For wind equipment that does not possess this capability, the SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency. For these units compliance with the Requirement is shown by maintaining documentation explaining the unit's operating limitations.		
Great River Energy		
BC Hydro	Yes	The standard apparently favours ambient monitoring as a verification method. While this method has certain advantages over methods traditionally used to verify response of turbine-governors (off-line and on-line step tests), it should be well understood that its implemention is associated with additional costs and difficulties. The question is how would GOs make use of ambient monitoring data to verify the models? GOs are responsible only for equipment models and would not normally have overall system models which are necessary to evaluate the results of ambient monitoring. That puts the focus back on traditional approaches.
Response: Thank you for your comment. Software tools are available for use to record response at the generator terminals (or highside of the GSU) for model verification. The response of the modeled generator to the applied signal can be used to demonstrate that model performance matches measured performance. Overall system model verification is not required to verify the individual generator model.		
Northeast Utilities	Yes	In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
Response: Thank you for your comment. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity		

Organization	Yes or No	Question 6 Comment
experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.		
Constellation Power Generation	Yes	CPG is unsure as to what Requirement 2.1.1 is actually requiring. Please explain the difference between an on-line response to a frequency excursion vs. a recorded response. This sub requirement seems to be implying that each GO has the necessary equipment to capture an on line or recorded response. Is it the intent of the drafting team to force GOs to install equipment in order to comply with R2.1.1 along with the conditions found in Attachment 1? CPG would also like clarification on Requirement 2.1.5. Outer loop controls don't affect the governor control (frequency loop). Lastly, CPG would like the SDT to describe how a GO will know that a frequency excursion event occurred on the BES if their facility was unaffected and the facility did not have equipment sensitive enough to measure within .15 Hz.
Response: Thanks for your comment. The language of Requirement R2 subpart 2.1.1 has been revised. The equipment required to capture an on-line frequency response is relatively simple. Experience indicates the MW signal sent to a PI recording systems is adequate if the time resolution is set to two seconds or better. The effects of outer loop controls are important to understand to properly capture the frequency response of the unit. The SDT understands that a list of suitable frequency disturbances will be compiled by other NERC initiatives and made available to industry.		
Consolidated Edison Co. of NY, Inc.	Yes	In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
Response: Thank you for your comment. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. As a basis, the SDT recognized that the governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds which the SDT believes corresponds to 80% of connected MVA or greater for each Interconnection are proposed. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes		

Organization	Yes or No	Question 6 Comment
requiring verification of these plants and has added language to the Applicability section to capture this intent.		
American Electric Power	Yes	Standard models may not be available for wind units and wind facilities (which appear to be within scope of 4.2), particularly aggregate reactive and frequency response controls. As a result, it might be difficult to obtain and provide such information.
Response: Thank you for your comment. Some wind equipment have controls that can respond to a frequency excursion for which non-proprietary models exist. For wind equipment that does not possess this capability, the SDT has added another row to Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency. For these units compliance with the Requirement is shown by maintaining documentation explaining the unit's operating limitations.		
Ingleside Cogeneration LP	Yes	Like many Generator Owners, Ingleside Cogeneration LP has limited experience with transmission system modeling and scenario planning. Although in general we have a good working relationship with our Transmission Planner, MOD-027-1 may border on exchanging information which either entity may consider to be proprietary. In addition, the extra costs required to deploy recording equipment and to engage external experts to assist with frequency response planning are not budgeted. With this in mind, a priority deployment may be more appropriate - where the most critical facilities in each Region are evaluated first.
Response: Thank you for your comment. The information referenced by this standard needs to be shared between the Generator Owner and Transmission Owner to facilitate essential study work. The implementation plan provides sufficient time for budget planning. Specifically, the proposed phased implementation plan has effective dates of 3, 5, 7 and 9 years after appropriate regulatory approval.		
Wisconsin Public Service Corp	Yes	We have a number of questions and concerns as follows: o While the Standard uses the word "verified" and "verification" loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. o If a simulation study results in response characteristics that does not match an on-line step input test response,

Organization	Yes or No	Question 6 Comment
		can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? o We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.

Response: Thank you for your comment. The turbine/governor and load control or active power/frequency control response is a characteristic of the generator equipment, not the external system. The intent is that the Generator Owner should strive to match the predicted response of the complete model with the actual response recorded. Verification of individual parameters should not be the emphasis of the model verification effort. Also note an off-line step test is not allowed to be performed per the current draft language of the standard. The SDT is requiring either a) an on-line step in frequency reference test or b) ambient measurements for a naturally occurring frequency deviation – both of which ensure the effect of MW setpoint control is captured – or c) a partial load rejection test with the requirement that differences between the differences any modes that are disabled as soon as the generator breaker is opened (such as load or set point control).

It is true that modifying a parameter will alter the predicted response of the model however, an individual parameter should not be assigned an incorrect value for the sake of verifying the model. Ideally, model parameters should be altered to more accurately reflect the physical characteristic represented. However, based on actual experience in the WECC region, the ultimate goal of the verification process is to sufficiently refine model parameters to consistently approximate equipment response to a frequency excursion. The SDT recognizes expertise is required to perform model verification and this is the reason why the model verification periodicity proposed is a 10 year cycle.

Especially considering that the units contained in the Applicability is a subset of the NERC Compliance Registry, the SDT believes that the drafted standard is cost efficient to the industry. As a basis, the SDT recognized that the governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard is expected to result in improved accuracy of the governor model used in dynamic simulation. Utilizing engineering judgment, based in part on recent entity experience with verifying governor models, the SDT is proposing to require verification of governor models associated with 80% or greater of the connected MVA in each Interconnection. Given the increasing importance of renewable generation plants comprised of several small units, the SDT also proposes requiring verification of these plants and has added language to the Applicability section to capture this intent.

Organization	Yes or No	Question 6 Comment
GE Energy	Yes	The second bullet, in part B “Requirements,” section R1, page 4: The word “library” should be removed from the phrase “system model library block diagrams,” since not all wind manufacturers have standard library models.
Response: Thank you for your comment. The SDT believes that the word “library” is appropriate in this context. User defined models can still be utilized for verification to the extent that the Transmission Planner is willing to accept them.		
ISO New England	Yes	In requirement R2.1.1 what is meant by frequency excursion/reference change?This standard must require that all models provided are non-proprietary, otherwise a major reason (NERC MMG) for model collection will be undermined. This will prevent coordination of studies across regions which may undermine reliability.We are not sure if we have the correct version of draft MOD-027-1. In the “Differences also exist between MOD-026-1 and MOD-027-1” Section of this Comment Form, there are several mentions of Requirement R1 Part 1.x which we are unable to find in the draft standard. For example, Requirement R1 Part 1.2.1 in (5), R1 Part 1.3 in (6), R1 Part 1.4 in (7), and R1 Parts 1.1, 1.3, 1.4 in the “Compliance Elements for MOD-027-1” Section. Also, the referenced MOD-026-1 does not have the parts mentioned in this Comment Form. Is the background provided in this comment form incorrect, or are the posted versions of MOD-026 and MOD-027 out of date?In requirement R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by a many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping.
Response: Thank you for your comments. The SDT agrees with your comment that it is important for the model to be non-proprietary. This is why the standard requires each Generator Owner provide data for models that are acceptable to the Transmission Provider. The SDT apologizes for comment form errors discovered. The requirement for positive damping mandates the Generator Owner provide a response if an otherwise acceptable simulation is negatively damped after introducing a new model. This requirement recognizes the fact that equipment must be positively damped during actual operation, so negative damping occurring during simulation would indicate incorrect modeling. Initialization errors and oscillations during steady state conditions would also be an indication of model deficiencies. Each of these tests are components of an established industry practice for assuring model integrity.		

Organization	Yes or No	Question 6 Comment
GenOn Energy		
Manitoba Hydro	Yes	-MH disagrees with the SDT's assumption that the majority of turbine/governor and load control functions will be verified through ambient monitoring. If both turbine/governor and load control functions as well as excitation control functions are to be
Response: Thank you for your comment. Unfortunately part of the comment provided is missing. The SDT believes ambient monitoring is the preferred method for verifying turbine/governor and load control function models. Staged tests do not always capture the effects of load controllers and control modes. However, this standard does permit the optional utilization of stage tests (both on-line reference change and partial load rejections, though the impacts of any wrap around control modes not captured during the staged test have to be considered). The SDT has constructed the standard such that a Generator Owner can wait for a suitable event, even if it takes longer than 10 years when the unit is in a mode that is expected to govern, as opposed to requiring a on-line staged test that a significant number of Generator Owners are not comfortable performing and/or based on the vintage of equipment, do not have the capability of performing.		
Duke Energy	Yes	1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don't match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. 8) The frequency response of a generation unit is intrinsically connected to the Pmax values used in various system models (old MOD-24). These 2 validation efforts should be connected and the following modeling

Organization	Yes or No	Question 6 Comment
		parameters defined and addressed:Pmax o The continuous operating limit o The ultimate max emergency output. o Should there consider weather conditions (summer or winter, etc.). o PMAX associated with Transient stability - is it the same as for LF o Is this on the order of 105% or 110% or ??% of normal max loading A graphic illustrating this point has been provided to the SDT.
Response: Thank you for your comment. 1) The SDT revised Requirement 2.1.1. 2) Based on this and other comments, the SDT lengthened the R1 time frame to 90 days to match the time frame in the associated VSL. 3) The SDT revised Severe VSL language for R2. 4) The SDT agrees the incorrect grammar and has incorporated language similar to what you suggested. 5) The SDT agrees and has incorporated suggested language. 6) The SDT agrees and has incorporated suggested language. 7)) The SDT regrets the copy and paste errors and has corrected them. 8) The SDT recognizes that to obtain the correct frequency response, the frequency control model needs to limit the modeled response when units are base loaded or operated with valves wide open. The industry is working on resolving this issue and the SDT believes that the proposed MOD-027 provides an appropriate framework. Attachment 1 has been revised to allow owners of units/plants to provide a statement describing control limitation for units that do not provide frequency response as evidence of compliance with the requirement. The SDT did not receive a graphic. However, the SDT can say that loadflow based Pmax is not the same as the dynamic model maximum power.		
Lincoln Electric System	Yes	Under the Applicability Section, 4.2 Facilities, the “applicable units” are stated to have an average capacity factor greater than 5% over the last three calendar years and that the “majority of industry agreed with the standard MOD-026-1 5% capacity factor threshold” (Background Information: “Standard MOD-027-1” - #3). LES is concerned that the industry builds power flow models for future summer peak conditions, and therefore, LES is not convinced that the capacity factor threshold of less than 5% is a good indication of what units are on-line in these future models. Therefore, the goal for verification of the dynamic models associated with 80% or greater of the connected MVA per Interconnection may not be achieved. LES believes that a check (i.e., survey) of the ERAG MMWG models would be a good indication of whether or not the capacity factor threshold satisfies this objective.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. The SDT believes that the 5% capacity factor threshold functions to establish a balance between verifying modeling information for units that play an important role in the reliability of the BES and units that report information which is not verified because they are seldom online and have a relatively diminished reliability role. While it is true that units that have a capacity factor that is marginally greater than 5% could result in a long ambient monitoring period before capturing a response suitable for model verification, the SDT believes that it is better to wait for a suitable event as opposed to requiring a on-line staged test that Generator Owners are not comfortable performing and even argue is not an accurate test. Finally, by its inherent nature, an expected summer peak load ERAG MMWG case will include many on-line low capacity factor units. However, the SDT recognized that the governor models and model data for all generators in the ERAG MMWG case are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test initiated by the Phase III-IV SDT, performing the activities specified in the draft standard for 80% or greater of units making up the total interconnected MVA is expected to result in an improvement of the accuracy of the governor models used in dynamic simulations.		
CPS Energy		
Independent Electricity System Operator	Yes	We do not agree with some of the requirements.i. R1: Standards should stipulate the “what’s” not the “how’s”. To avoid the perception that the requirement is prescribing the “how”, we suggest simplifying the language of Requirement R1 by replacing “Instruction on how to obtain” with “Instructions for obtaining”.Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process.ii. R2.1: The phrase “models acceptable to its Transmission Planner” begs the question on what is deemed acceptable and what if the GO disagrees with the TP’s determination. To address the two issues, we suggest adding a requirement for the TP to specify the models (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to “in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). Another possibility would be to remove this phrase altogether since the Transmission Planner would in any case have to declare the model “useable” pursuant to Requirement R5.iii. R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels,

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable.iv. We decide not to comment on the Measures and other compliance elements at this time in view of the comments, above.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Requirement 1 does describe the “what” and avoids being prescriptive. Upon request, the Transmission Planner provides requested information to the Generator Operator. Items that the Generator Owner can request from the Transmission Planner are stated in requirement 1 (refer to the bulleted items). The Transmission Planner is only required to provide the items if requested to do so and as such the standard language and format is correct.

Since the Transmission Planner is the user of the model, submitted models must be acceptable to the transmission planner to be useful. The first bullet under requirement R1 does require the Transmission Planner to provide instructions on how to obtain the list of acceptable models.

The requirement for positive damping mandates the Generator Owner provide a response if an otherwise acceptable simulation is negatively damped after introducing a new model. This requirement recognizes the fact that equipment must be positively damped during actual operation, so negative damping occurring during simulation would indicate incorrect modeling. Initialization errors and oscillations during steady state conditions would also be an indication of model deficiencies. Each of these tests are an established industry practice for assuring model integrity.</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>No</td><td></td></tr>
<tr><td>Ameren</td><td>Yes</td><td>(1) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (2) R4 of the Draft references footnote 5. It appears this footnote is overly broad and requires editing to precisely identify equipment systems that can truly impact system reliability. This footnote should be edited so it becomes either a new Requirement or a new set of sub-requirements. No other systems should be included.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. 1) The standard has been revised for clarity regarding the meaning for the “point of interconnection.” The SDT believes a formal definition is not needed since the point of interconnection is described in the standard.</td></tr>
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Organization	Yes or No	Question 6 Comment
2) In the development of Footnote 5, the SDT strove to cover all reasonable examples that might result in the alteration of equipment response. However, the requirement leaves the responsibility for determining what alters equipment response to the Generator Owner.		
Indeck Energy Services	Yes	This standard imposes significant costs on generators and requires them to, in many cases unless they are also a transmission company, to hire consultants to conduct the verification. There is no evidence that unverified model data for units smaller than the level of the NERC Reportable Disturbance for the control area will have any impact on BPS reliability.
Response: Thank you for your comment. This standard has been vetted including SAR development and field testing. Industry believes that this standard is needed. The STD recognizes there are costs associated with compliance and has proposed a standard applicability limited to the most critical units/plant listed in the compliance registry criteria.		
Oncor Electric Delivery Company LLC	No	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

END OF REPORT

Consideration of Comments on Generator Verification (PRC-019-1)—Project 2007-09

The Generator Verification drafting team thanks all commenters who submitted comments on the first posting of PRC-019-1, Coordination of Generating Unit/Facility Voltage Regulating Controls with Generating Unit/Facility Capabilities and Protection (Project 2007-09). These standards were posted for a 30-day public comment period from June 15, 2011 through July 15, 2011. The stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing 9 of the 10 industry segments, as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2563, or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT posted PRC-019-1 for a 30 day formal comment period from June 15-July 15, 2011. The majority of stakeholders agreed with the proposed standard and provided some comments for revisions to the standard. The Applicability to Transmission Owners was clarified to include only those that own synchronous condenser(s) ad follows:

4.1.2 Transmission Owner that owns synchronous condenser(s)

The GVSDT asked stakeholders if they believed that the proposed PRC-019-1 standard was written to be "technology neutral" such that it can be used for all forms of generation connected to the BES. The vast majority of stakeholders believe that the standard is technology neutral. Several stakeholders that expressed concerns commented that the standard may not work for photovoltaic or wind technologies. The GVSDT agrees that while some of the standard elements might not apply to all technologies, most elements and the example diagrams (in general) would apply to all technologies.

One stakeholder recognized that the SSSL calculation plot used in the example diagrams is based on a fixed field current, which would require the excitation system to be in Manual Mode. The GVSDT, having previously considered this and knowing the excitation system to typically be in Auto Mode per VAR-002, provided the following response: The calculation of the SSSL based on a fixed field current value is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex.

The GVSDT asked stakeholders if they agreed with the applicability to synchronous condensers. The question contained a limit of ≥50 MVA while the standard contained ≥20

[1] The appeals process is in the Standard Processes Manual:
http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

MVA. The GVSDT intended for ≥20 MVA to be the correct number. Many stakeholders pointed out this discrepancy and agreed with the ≥20 MVA threshold. The GVSDT will ask this question again in the next posting.

Some stakeholders suggested higher MVA limits for units applicable to this standard. The GVSDT based the applicability criteria on the current Compliance Registry Criteria and the current posted draft of the BES definition, both of which currently set the applicability threshold at 20 MVA for individual units. The SDT felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry Criteria and the BES definition.

Constellation Power pointed out that repeating the Compliance Registry Criteria within the standard is not wise since the standard must be changed if the Compliance Registry Criteria changes. The SDT agrees with this logic but felt it was necessary to include the appropriate Compliance Registry Criteria within the standard because the standard also applies to synchronous condensers, which are not explicitly mentioned in the Compliance Registry Criteria. If the Compliance Registry Criteria language for generating units was not included in the standard the standard could be interpreted to apply only to synchronous condensers and not to generators.

Stakeholders were asked if they thought that variable static reactive sources that are not located at generating facilities should be included in the standard. The vast majority of stakeholders did not see a reliability need for including variable static reactive sources that are not located at generating facilities. This equipment is normally protected for internal failures and do not have similar equipment protection such as synchronous generators using generator field limiters and over- and under-excitation protection. The SDT has determined that variable static reactive resources not located at generating facilities are outside the scope of this project. For these reasons, including static reactive resources not located at a generating facility are not part of this standard.

The majority of stakeholders agreed with the Purpose Statement of PRC-019-1. The GVSDT revised the Purpose Statement of the standard for clarity based on stakeholder comments. The revised Purpose Statement is:

> To improve the reliability of the Bulk Electric System by ensuring coordination of generating unit/facility or synchronous condenser voltage regulating controls and limit functions with generator capabilities and protection system settings.

The proposed effective dates provide a “phased-in” approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/facilities. The majority of stakeholders agreed with the phased in approach. Stakeholders pointed out that, for jurisdictions where regulatory approval is not required, the 100% completion item was missing. The GVSDT added item 5.2.5:

> 5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

Stakeholders were asked about Section G of the standard which provides examples of how the coordination can be demonstrated. The majority of stakeholders agreed with the information provide and several stakeholders made suggestion for clarifying language. Specific changes were made to Section G of the standard based on comments received. These changes included:

1. The example diagrams added that they are drawn at nominal voltage and frequency.

2. The formula for calculating the radius of the SSSL was corrected.

3. The items “under-excited limiters or minimum excitation limiters” and “over-excited limiters or maximum excitation limiters” have been placed in the bulleted list of the standard.

4. The SDT changed “protective” to “protection” within the standard to be consistent with Section G.

5. The SDT added a reference document for use in calculation of SSSL.

Several commentators were concerned that Section G has a method for illustrating coordination of AVR limiter/protection functions with other protection systems. The SDT agrees that there are numerous ways of demonstrating coordination and does not prescribe any particular method. Any protective function that is enabled should be evaluated for proper coordination.

The SDT reviewed the requests to remove the distance relay and volts/hertz relay elements from the standard. It is the belief that these two elements remain in the document since a) the distance element should illustrate coordination with field forcing controls of the AVR, and b) the volts per hertz function can operate with the unit on-line under certain operating conditions.

Index to Questions, Comments, and Responses

1. Do you agree that the standard, as written, is "technology neutral," such that it can be used for all forms of generation connected to the BES? If you do not agree, please state your reasons and suggest alternatives to make the standard technology neutral in the Comment area. 15

2. The SDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated equal to or greater than 50 MVA. The standard applies to generating units/Facilities that meet the Compliance Registry criteria and to synchronous condensers rated 50 MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the Comment section. 22

3. As currently drafted, this standard applies to synchronous generators, synchronous condensers, and variable static Reactive resources located at asynchronous generating Facilities (e.g., wind and solar sites). Do you see a reliability need for including variable static Reactive resources (e.g., static VAr compensators) that are not located at generating sites in this standard? Please explain your answer in the comments block. 33

4. The SDT revised the Purpose of the standard in accordance with the SAR, "To improve the reliability of the Bulk Electric System by preventing tripping of generating units/Facilities due to miscoordination of generating unit/Facility voltage regulating controls, and limit functions with generator capabilities and Protection System settings." Do you agree with the revised Purpose of the standard? If not, please provide suggested language changes in the Comment section. 44

5. The proposed effective dates provide a "phased-in" approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/Facilities. Do you agree with the proposed implementation schedule? If not, please provide an alternative implementation schedule, approach, and supporting information in the comments. 52

6. Do you agree that the evidence, documents, and functions listed in Section G are sufficient for giving the Generator Owner/Transmission Owner examples of how the coordination can be demonstrated? If not, please provide suggested language changes to the Measure and supporting information in the Comment section. 61

7. Do you agree with the data retention language listed in the Compliance section of the draft standard? If not, please comment and provide alternative data retention language. 69

8. Are you aware of the need for any regional variances to this standard? If yes, please explain in the comment section. 78

9. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain in the Comment section. 84

END OF REPORT 101

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-Serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory, or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council , LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

12. David Kiguel	Hydro One Networks Inc.	NPCC	1
13. Michael R. Lombardi	Northeast Utilities	NPCC	1
14. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15. Bruce Metruck	New York Power Authority	NPCC	6
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17. Robert Pellegrini	The United Illuminating Company	NPCC	1
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19. Saurabh Saksena	National Grid	NPCC	1
20. Michael Schiavone	National Grid	NPCC	1
21. Wayne Sipperly	New York Power Authority	NPCC	5
22. Donald Weaver	New Brunswick System Operator	NPCC	2
23. Ben Wu	Orange and Rockland Utilities	NPCC	1
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
3.	Group	Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tino Zaragoza	IID	WECC	1
2. Sammy Alcaraz	IID	WECC	3
3. Diana Torres	IID	WECC	4
4. Marcela Caballero	IID	WECC	5
5. Cathy Bretz	IID	WECC	6

				1	2	3	4	5	6	7	8	9	10
4.	Group	Albert DiCaprio	IRC Standards Review Committee (joint comments)		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Terry Bilke	MISO	RFC	2
2. Patrick Brown	PJM	RFC	2
3. Ben Li	IESO	NPCC	2
4. Mark Thompson	AESO	WECC	2
5. Steve Myers	ERCOT	ERCOT	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	David Thorne	Pepco Holdings Inc Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3
2.	Alivan Depew	Pepco Holdings Inc	RFC	1, 3

				1	2	3	4	5	6	7	8	9	10
6.	Group	Jonathan Sykes, Chair	NERC System Protection and Control Subcommittee	X			X	X					X

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
7.	Group	Carol Gerou	Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Power Dist	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Copperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
10.	Joseph DePoorter	Madison Gas and Electric Company	MRO	3, 4, 5, 6
11.	Scott Nichols	Rochester Public Utilities	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
13.	Richard Burt	Minnkota Power Cooperative	MRO	1, 3, 5, 6
14.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
15.	Scott Bos	Muscatine Power and Water	MRO	3, 4, 5, 6
16.	Lee Kittleson	Otter Tail Power Company	MRO	5, 1, 3, 6

Additional Member	Additional Organization	Region	Segment Selection
17. Marie Knox	Midwest ISO	MRO	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jonathan Hayes	SPP Reliability Standards Development Team										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Reynolds	Sunflower Electric Power Corporation	SPP	1
2.	Valerie Pinamonti	AEP	SPP	1, 3, 5
3.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
5.	Louis Guidry	CLECO	SPP	1, 3, 5
6.	Sean Simpson	McPhearson Board of Public Utilities	SPP	1, 3, 5
7.	Robert Rhodes	SPP	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Co.	SERC	1
2.	James Manning	NC Electric Membership Corp.	SERC	1
3.	Philip Kleckley	SC Electric & Gas Co.	SERC	1
4.	Pat Huntley	SERC Reliability Corp.	SERC	10
5.	Bob Jones	Southern Company Services	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Tim Brown	Idaho Power-Power Production					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Guy Colpron	Idaho Power	WECC	5
2.	Mark Pfeifer	Idaho Power	WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Phil Pierce	Santee Cooper	SERC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3. Paul Camilletti		Santee Cooper	SERC 5										
4. Rene Free		Santee Cooper	1										
5. Tom Curtis		Santee Cooper	SERC 5										
12.	Group	Annette Bannon	PPL Generation					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Leland McMillan	PPL Montana, LLC	WECC	5
2.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
3.		PPL Brunner Island, LLC	RFC	5
4.		PPL Holtwood, LLC	RFC	5
5.		PPL Martins Creek, LLC	RFC	5
6.		PPL Montour, LLC	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		MRO	5, 6
2.	Connie Lowe		SERC	5, 6
3.	Michael Gildea		RFC	5, 6
4.	Larry Whanger		SERC	5
5.	Mike Crowley		SERC	1, 3
6.	Jeff Bailey		MRO	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Baznik	FE	RFC	1
2.	Bill Duge	FE	RFC	5
3.	Brian Orians	FE	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Joe Spencer - SERC Bob Jones - DRS chair	SERC Dynamics Review Sub-committee										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

				1	2	3	4	5	6	7	8	9	10
16.	Group	Mallory Huggins	NERC Staff										

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
17.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Brown	PSE&G	RFC	1, 3
2.	Clint Bogan	PSEG Fossil	RFC	5
3.	Peter Dolan	PSEG ER&T	RFC	6
4.	Scott Slickers	PSEG Fossil	NPCC	5
5.	Eric Schmidt	PSEG ER&T	NPCC	6
6.	Mikhail Falkovich	PSEG Fossil	ERCOT	5

				1	2	3	4	5	6	7	8	9	10
18.	Group	Joe Spencer - SERC staff	SERC Generation sub-committee										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Jason Marshall	ACES Power Members						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Jones	AEPCO/SWTC	WECC	1, 3, 5
2.	Mohan Sachdeva	Buckeye Power	RFC	4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Bo Jones	Westar Energy	X		X		X	X				
22.	Individual	Antonio Grayson	Southern Company					X					
23.	Individual	David Thompson	Tennessee Valley Authority GO					X					
24.	Individual	David Youngblood	Luminant Power					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	David Miller	Lakeland Electric	X									
26.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
29.	Individual	Edward Cambridge	APS	X		X		X					
30.	Individual	Brad Haralson	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
32.	Individual	Greg Campoli	New York Independent System Operator		X								
33.	Individual	Samuel Reed	Tri-State Generation and Transmission, In.	X				X					
34.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
36.	Individual	Mace Hunter	Lakeland Electric	X		X		X					
37.	Individual	John Bee	Exelon	X		X		X					
38.	Individual	Michael Goggin	American Wind Energy Association								X		
39.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Bob Casey	Georgia Transmission Corporation	X									
41.	Individual	Jeanie Doty	Austin Energy					X					
42.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
43.	Individual	Michael Brytowski	Great River Energy	X		X		X					
44.	Individual	Vladimir Stanisic	BC Hydro	X	X	X		X					
45.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
46.	Individual	Amir Hammad	Constellation Power Generation					X					
47.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
48.	Individual	Thad Ness	American Electric Power	X		X		X	X				
49.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
50.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					
51.	Individual	Gary Chmiel	GE Energy										
52.	Individual	Kathleen Goodman	ISO New England		X								
53.	Individual	Dan Hansen	GenOn Energy					X					
54.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
56.	Individual	Eric Ruskamp	Lincoln Electric System	X		X		X	X				
57.	Individual	Jose H Escamilla	CPS Energy			X							
58.	Individual	Michael Falvo	Independent Electricity System Operator		X								
59.	Individual	Karen Alford	Gainesville Regional Utilities	X		X		X					
60.	Individual	Kirit Shah	Ameren	X		X		X	X				
61.	Individual	Rex Roehl	Indeck Energy Services					X					
62.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
63.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
64.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
65.	Individual	John Yale	Chelan County PUD	X				X	X				

1. Do you agree that the standard, as written, is "technology neutral," such that it can be used for all forms of generation connected to the BES? If you do not agree, please state your reasons and suggest alternatives to make the standard technology neutral in the Comment area.

Summary Consideration: The majority consensus of the stakeholders was "yes," the standard is technology neutral. Several of the "no" responders commented that the standard may not work for photovoltaic or wind technologies. The SDT agrees that while some of the standard elements might not apply to all technologies, most elements and the example diagrams (in general) would apply to all technologies.

One stakeholder recognized that the SSSL calculation plot used in the example diagrams is based on a fixed field current, which would require the excitation system to be in manual mode. The SDT, having previously considered this and knowing the excitation system to typically be in auto mode per VAR-002, provided the following; the calculation of the SSSL based on a fixed-field current value is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex.

Organization	Yes or No	Question 1 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
Response: Thank you for your comment. The SDT received input from owners and operators of wind and solar Facilities, as well as an OEM involved with these technologies. The examples provided contain some elements that may not apply to all technologies; though the diagrams, in general, would apply to all technologies.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		

Organization	Yes or No	Question 1 Comment
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric	Yes	

Organization	Yes or No	Question 1 Comment
Cooperative, Inc.		
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD		Cowlitz has no opinion.
Xcel Energy	Yes	
Lakeland Electric		
Exelon	No	The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (top of page 7) states "(F)or the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current." This conflicts with Requirement R1.1.1 that states "... assuming normal AVR control loop and system steady state operating conditions. Currently the two statements are in conflict with one another in that one requires a "fixed" field current (i.e., AVR in "manual") and the other requires "normal operation" (i.e., AVR in "automatic").The SDT needs to allow for automatic mode for AVR to accommodate those Generators that have redundant automatic channels as is the case for newer digital AVRs. This will allow the owner to use AVRs automatic mode when plotting SSSL.
Response: Thank you for your comment. The SDT agrees that the generators must normally operate in AVR mode. The calculation of the SSSL, based on a fixed-field current value, is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex. The SSSL is an element that applies only to synchronous generating units. It would not necessarily apply to wind or solar facilities.		
American Wind Energy	Yes	

Organization	Yes or No	Question 1 Comment
Association		
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
Response: Thank you for your comment. The SDT received input from owners and operators of wind and solar Facilities, as well as an OEM involved with these technologies. The examples provided contain some elements that may not apply to all technologies; though the diagrams, in general, would apply to all technologies.		
Constellation Power Generation	No	Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
Response: Thank you for your comment. Because this standard includes equipment that is not specifically listed in the Registry criteria (synchronous condensers), the SDT feels it is necessary to explicitly list the generating equipment included in the criteria. If the Registry criteria are revised in the future, this standard may have to be revised as well.		
Consolidated Edison Co. of	No	This draft standard appears to have been written from a traditional steam or combustion

Organization	Yes or No	Question 1 Comment
NY, Inc.		turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
Response: Thank you for your comment. The SDT received input from owners and operators of wind and solar Facilities, as well as an OEM involved with these technologies. The examples provided contain some elements that may not apply to all technologies; though the diagrams, in general, would apply to all technologies.		
American Electric Power	Yes	Though we agree that the standard as written is "technology neutral", its apparent neutrality might well be impacted by the definition of BES which is currently being revised. This topic might need to be revisited once the revised definition of BES has been approved.
Response: Thank you for your comment. If the definition of the BES is revised in the future, this standard may have to be revised as well.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP's gas and steam turbine units use voltage limiting and protection system technologies which are clearly referenced under PRC-019-1.
Response: Thank you for your comment.		
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	Yes	
Duke Energy	No	See response to Question #2 below.
Lincoln Electric System		
CPS Energy		

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indeck Energy Services		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

2. **The SDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated equal to or greater than 50 MVA. The standard applies to generating units/Facilities that meet the Compliance Registry criteria and to synchronous condensers rated 50 MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the Comment section.**

Summary Consideration: The majority of stakeholders agreed with the applicability of the standard.

Several stakeholders noted that the posted question mistakenly stated that the proposed standard applied synchronous condensers rated equal to or greater than 50 MVA, rather than the correct value of equal to or greater than 20 MVA. Four of the "no" votes were based on disagreeing with the 50 MVA threshold, and preferring the (correct) 20 MVA threshold.

A few stakeholders recommended applying the standard to units that are larger than 75 MVA, and pointed out that this is the threshold used in the current draft definition of the BES. Three more stakeholders also recommended a higher threshold. The SDT based the applicability criteria on the current Compliance Registry criteria and the current posted draft of the BES definition, both of which currently set the applicability threshold at 20 MVA for individual units. The SDT felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry criteria and the BES definition. If the Compliance Registry criteria and/or the BES definition changes in the future, it is likely that the applicability for this standard should be changed as well.

Constellation Power pointed out that repeating the Compliance Registry criteria within the standard is not wise since the standard must be changed if the Compliance Registry criteria changes. The SDT agrees with this logic, but felt it was necessary to include the appropriate Compliance Registry criteria within the standard because the standard also applies to synchronous condensers, which are not explicitly mentioned in the Compliance Registry criteria. If the Compliance Registry criteria language for generating units was not included in the standard, the standard could be interpreted to apply only to synchronous condensers, and not to generators.

A couple of stakeholders stated that the standard should not apply to synchronous condensers because they are not included in the Compliance Registry. The SDT feels, as do many other stakeholders, that, for reliability reasons, this standard needs to apply to synchronous condensers, and it is appropriate to list equipment that is not in the Registry criteria.

Organization	Yes or No	Question 2 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Response: Thank you for your comment. The proposed draft of the BES definition that is posted on the NERC website includes individual units of 20 MVA and greater, not 75 MVA. If the draft changes in the future, this standard and others may need to be revised.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	Question #2 mentions that a threshold was chosen by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
NERC System Protection and Control Subcommittee	No	The SPCS notes that the posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. The SPCS agrees with the 20 MVA threshold in the posted standard.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	

Organization	Yes or No	Question 2 Comment
SPP Reliability Standards Development Team	Yes	This question refers to the applicability of the standard yet doesn't reflect the wording in this question. In the standard the applicability for synchronous condensers is 20 MVA due to it being lumped with single units. This needs to be broken out in the applicability section of the standard.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		
PPL Generation	No	See item 1 in Question 9 Response.
Dominion	Yes	
FirstEnergy	Yes	Although we agree with the applicability, the standard that was posted does not mention the 50 MVA threshold.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
SERC Dynamics Review Sub-committee		
NERC Staff	No	The posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. We agree with the 20 MVA threshold in the posted standard.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group	No	The question and the standard contradict each other. The standard states that it applies to “synchronous condensers > 20 MVA” not “rated > 50 MVA.We do not agree with the threshold MVA applicability for generators. Field testing and industry history do not warrant the need for such a low MVA threshold. We suggest that the threshold be for larger units (rated > 500 MVA) that have the ability to significantly impact BES reliability. The resources required to apply this standard to smaller units compares to the benefits to the BES and the GO are generally not justified in most regions. However, it can be argued that smaller units can have a significant impact on the BES, especially in weak systems. Therefore, we recommend that an inclusion criteria be developed that would require units in such regions to be included.
Response: Thank you for your comment. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	In the standard the applicability for synchronous condensers is > 20 MVA for an individual unit. Additional language should be added to the standard to address the applicability for generating units/facilities.
Response: Thank you for your comment. The SDT believes that Section 4.2.1 does address the applicability for generating units/Facilities.		
Southern Company	No	We feel that this standard is not applicable for solar facilities. For other facilities, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit, 15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA

Organization	Yes or No	Question 2 Comment
		in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units â ‰ ¤ 75MVA may be identified by a transmission entity as critical for BES reliability. Thus, the standard could include requirements applicable to such units where identified by a tranmission entity as critical for BES reliability.
Response: Thank you for your comment. Miscoordination between inverter capabilities and protection would apply to solar facilities. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas		
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Tri-State Generation and Transmission, In.</td><td>Yes</td><td>The standard seems to indicate 20mva instead of the stated 50mva.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.</td></tr>
<tr><td>Cowlitz County PUD</td><td>No</td><td>The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Using the Compliance Registry Criteria’s generator MVA name plate ratings to assign applicability of the Standard is questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. If models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Further, the unit versus plant MVA criteria is illogical. If the BES can withstand the loss of a 75 MVA plant, then logically it will withstand the loss of a 20 MVA unit. Cowlitz believes that after the appropriate study is completed, the applicability line should be somewhere in the range of a verified nominal plant or unit output of 100 to 200 MVA. Last of all, applicability should be assigned to BES generation when it has been defined.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units. The GVSDT is not attempting to justify the NERC registration criteria through this standard. We are simply using it as the basis for Facility applicability.</td></tr>
<tr><td>Xcel Energy</td><td>Yes</td><td>There is a discrepancy between the question and the 20 MVA size limit for synchronous condensers in the draft standard. We believe 50 MVA is the better value.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
Lakeland Electric		
Exelon		
American Wind Energy Association	Yes	
Tacoma Power		
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro		
Northeast Utilities	No	Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Response: Thank you for your comment. The proposed draft of the BES definition that is posted on the NERC website includes individual units of 20 MVA and greater, not 75 MVA. If the draft changes in the future, this standard and others may need to be revised.		
Constellation Power Generation	No	Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the

Organization	Yes or No	Question 2 Comment
		compliance registry change.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
Consolidated Edison Co. of NY, Inc.	No	Generally only units larger than 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by the BES SDT.
Response: Thank you for your comment. The proposed draft of the BES definition that is posted on the NERC website includes individual units of 20 MVA and greater, not 75 MVA. If the draft changes in the future, this standard and others may need to be revised.		
American Electric Power	No	It needs to be explicitly stated whether or not a Transmission Owner is held under R1 if they do not own synchronous condensers. This might be achieved by adding additional language to 4.1.2 stating that the standard applies to those who own facilities as specified in 4.2.Usage of the words “coordinate” and “coordination” seems ambiguous, and might be open to interpretation. In other standards these words are often used to describe communication between NERC functions rather than ensuring that necessary and sufficient settings exist among equipment types to permit them to operate in a pre-determined sequence.The threshold of 50MVA is not mentioned in the draft standard. Rather, 4.2.1 specifies a threshold of 20MVA.It appears the term “synchronous condenser” has been omitted from R1. Suggest using "Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate its generating unit, generating Facility, or synchronous condenser voltage regulating system controls, including limiters and protection functions with the generating unit and Facility or synchronous condenser capabilities and protective system settings; to include as applicable".
Response: Thank you for your comment. The Applicability section of the draft standard has been changed to explicitly show that the standard only applies to TOs that own synchronous condensers. The concept of “coordination,” as applied to protective relays, limiters, and equipment capabilities, is commonly understood in the industry as meaning their desired sequence of operation. The value of 50 MVA was mistakenly used in the question on this form. The SDT agrees with your suggested wording revision to R1. The SDT also agrees that the Application section needed to be clarified for TOs, and has modified Section 4.1.2 to state that the standard only applies to TOs that own synchronous condensers.		
Ingleside Cogeneration LP	No	PRC-019-1 is appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be

Organization	Yes or No	Question 2 Comment
		not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System - this determination should rest with them.
Response: Thank you for your comment. For reliability reasons, this standard needs to apply to synchronous condensers, and it is appropriate to list equipment that is not in the Registry criteria. Many elements of the Bulk Electric System are not specifically named in the Registry criteria or definition of the BES. For example, PRC-005 deals with Protection Systems, which are not specifically named in the BES definition or the Registry criteria.		
Wisconsin Public Service Corp		
GE Energy		
ISO New England	Yes	Yes, however the standard should not rewrite the Compliance Registry as attempted. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry's wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity's restoration plan. If the NERC standards become effective for non-material 9 MVA black start units those units will likely drop out of the program. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
Response: Thank you for your comment. The SDT agrees to use the wording in the current version of the Registry criteria. Because this standard includes equipment that is not specifically listed in the Registry criteria (synchronous condensers), the SDT feels it is necessary to explicitly list the generating equipment included in the Criteria. If the Registry criteria are revised in the future, this standard may have to be revised as well.		
GenOn Energy		
Manitoba Hydro	No	The 50MVA criteria in question 2 does not appear in the draft standard. If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		
Duke Energy	No	We feel that this standard is not applicable for solar facilities or induction type generators used in some wind farms. Several different exemption criteria are specified in the various GVSDT standards. We understand the distinction made for MOD-26/27 (100MVA) from the MOD-25 criteria (75MVA). The standard likely should be consistent with one or the other, rather than having a 3rd criteria (50MVA). For this standard, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit, 15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units â‰¤ 75MVA may be identified by a transmission entity as critical for BES reliability. Regional criteria are allowed to address these concerns to make requirements applicable to such units identified as critical for BES reliability in that region.
Response: Thank you for your comment. Miscoordination between inverter capabilities and protection would apply to solar Facilities. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		
Gainesville Regional Utilities	Yes	

Organization	Yes or No	Question 2 Comment
Ameren	Yes	
Indeck Energy Services	No	Not sync condensers
Response: Thank you for your comment. The SDT believes that synchronous condensers are as important a Reactive resource as synchronous generators and should be included as applicable equipment in this standard.		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	IMPA supports the application of the standard to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 50MVA and greater.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

3. **As currently drafted, this standard applies to synchronous generators, synchronous condensers, and variable static Reactive resources located at asynchronous generating Facilities (e.g., wind and solar sites). Do you see a reliability need for including variable static Reactive resources (e.g., static VAr compensators) that are not located at generating sites in this standard? Please explain your answer in the comments block.**

Summary Consideration: —The majority of stakeholders did not see a reliability need for including variable static Reactive sources that are not located at generating Facilities. This equipment is normally protected for internal failures and do not have similar equipment protection, such as synchronous generators using generator field limiters and over- and under-excitation protection. The SDT has determined that variable static Reactive resources not located at generating Facilities are outside the scope of this project. For these reasons, the drafting team has not included static Reactive resources not located at a generating Facility.

Organization	Yes or No	Question 3 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage].Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Imperial Irrigation District (IID)	No	These devices are covered already under the VAR standards.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	No	Question #3 indicated that as currently drafted the standard applies to variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites). This is either specifically mentioned, or inferred, within the language of the June 15, 2011 Draft 2 standard. Regarding the question of a reliability need for including variable static reactive resources (e.g. static Var compensators) that are not located at generating sites in this standard, the answer is no. We see no need to make the standard applicable to Static Var Compensators (SVC's), whether they are located at generating sites, or remote from generating sites. An SVC is merely a thyristor switched / controlled capacitor or reactor. Maximum and minimum output is controlled by the firing controls to the thyristor, and is limited by the size of the installed shunt capacitor / reactor banks. When the thyristor is switched off there is no output. As the firing angle is increased toward the full on position the reactive output is increased until the full value of the shunt capacitor bank, or reactor bank, is reached. Protective devices and settings on the shunt capacitor bank and reactor bank within the SVC are typical of those employed on fixed banks. The control system merely provides a means to adjust the output between zero and full bank rating. As in the case of fixed banks, SVC protective devices are set assuming the full bank is in service. Therefore, if fixed shunt reactive banks are not subject to the standard, which they should not be, then SVC's should not be either. Synchronous machines, however, are a different story entirely. The quantity of reactive power produced by, or drawn into, the machine is a function of the machine field current. In an under-excited condition the unit may loose synchronism, or trip via loss of field protection, unless the voltage regulator (min. excitation limiter) is properly set and coordinated with the machine's capability and protective devices. Similarly, excessive Var output and / or terminal overvoltage caused by over-excitation of the field can result in equipment damage, or unit tripping, unless the voltage regulator is properly set and coordinated with the machine's capability and protective devices.
Response: Thank you for your detailed comment. While SVC's located at the bus of a variable energy resource would not coordinate with the individual generating equipment, the internal coordination between the current limiters and the protection of the SVC can be verified.		
NERC System Protection and	Yes	Devices such as Static Var Compensators and STATCOMs have equipment limitations, control

Organization	Yes or No	Question 3 Comment
Control Subcommittee		systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	Yes	We weren't able to locate the variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites) within the standard as the question suggests. We feel like variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites should have been included but would request that the team provide a limit on the size of these types of facilities. Our team isn't sure what a cutoff number would be, but would ask that the drafting team investigate this issue to come up with an appropriate number.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities, such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	No	

Organization	Yes or No	Question 3 Comment
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	Devices such as static var compensators (SVCs) and static compensators (STATCOMs) have equipment limitations, control systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser.Also, the standard must remain neutral as to the type of reactive resource, allowing for other technologies such as storage and demand-side regulation through electronically coupled loads that are relied upon for reliability purposes in the same vain as other reactive sources cited.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Public Service Enterprise Group	No	First, the inclusion of "variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites)" was not noted in the standard. Second, we do not believe that including other static reactive resources that are not located at generating sites would materially impact reliability
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls.. This equipment could include static Reactive resources (typically at asynchronous Facilities, such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
SERC Generation sub-committee		
ACES Power Members	No	It is not clear how this standard is applicable to variable static reactive resources located at asynchronous generating facilities. They do not appear in applicability section.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Arizona Public Service Company	No	
Westar Energy	Yes	Currently the requirements do not address variable static reactive resources located at asynchronous generating facilities as the question states. If the intent is for the standard to apply to variable static reactive resources located at asynchronous generating facilities, we propose language be added to the standard to address these resources. Yes, we do see a reliability need for including variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites. We propose that language be included to address the limit on the size of these types of facilities.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Southern Company		
Tennessee Valley Authority GO	No	
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	Yes	

Organization	Yes or No	Question 3 Comment
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.		
Dynegy Inc.		
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	The standard name indicates it applies to generating sites.
Response: Thank you for your comment.		
Cowlitz County PUD	Yes	But not at the 20/75 MVA name plate criteria. First the applicability should be tied to expected maximum MVA output. Second, the MVA basis should be established from a modeling study. Ultimately, the applicability should only include plants that are members of the BES once this has been defined.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Xcel Energy	No	These units are not tested under the proposed MOD-025-2, so should not be included in PRC-019-1.
Response: Thank you for your comment.		
Lakeland Electric		

Organization	Yes or No	Question 3 Comment
Exelon	No	Exelon does not see a reliability need to include static reactive resources in PRC-019. The standard as written is applicable to voltage regulating controls and limit functions with generator capabilities and protection system settings which is generator specific. Adding static reactive resources would require unnecessary additional guidance to be included in the standard. The maintenance and coordination of relays related to static reactive resources is currently covered in PRC-005 and modeling and studies are included in the MOD standard.
Response: Thank you for your comment.		
American Wind Energy Association	No	
Tacoma Power	No	Even if the variable devices or their impact is well defined, such as "Devices within 2 buses and that can affect the transmission system voltage plus or minus 5% or greater", including this requirement for variable static reactive sources could involve a wide scope of devices and potentially many owners and operators for very little improvement in reliability.
Response: Thank you for your comment.		
Georgia Transmission Corporation		
Austin Energy		
Wisconsin Electric	No	The primary applicability should be to rotating synchronous machines which must have their protection settings and excitation controls properly coordinated with the machine capability. It is not clear how this can be applied to wind generators.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT agrees that static Reactive resources not at generating Facilities should not be within the scope of this standard.		
Great River Energy		

Organization	Yes or No	Question 3 Comment
BC Hydro	No	
Northeast Utilities	Yes	Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage].Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	Yes	Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage].Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
American Electric Power	No	AEP sees no benefit to the reliability of the BES in adding to this standard the controls associated with static reactive resources.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP is hesitant to require validation of components which have not been clearly identified as a reliability imperative under either the revised definition of the BES or CIP-002-4's bright-line criteria.
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	No	Static VAr compensators do not belong in a generation standard.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT agrees that static Reactive resources not at generating Facilities should not be within the scope of this standard.		
Duke Energy	No	See the purpose of the standard. It's not clear why a generation protection/control coordination requirement would be applicable to non-generation resources, other than maybe synchronous condensors.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar).		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	The SVCs serve quite different purpose and react to system conditions quite differently compared to their generator/synchronous condenser counterparts. Further, SVCs do not "trip", per se, they vary their reactive outputs including going to and crossing 0 MVar and hence some

Organization	Yes or No	Question 3 Comment
		of the interactions between the device and its protection systems in the case of generators/synchronous condensers are not applicable to SVCs.
Response: Thank you for your detailed comment.		
Gainesville Regional Utilities	No	
Ameren	Yes	Question should be directed at transmission planners. I would believe the static VAr compensators are required for system voltage support, similar to synchronous condenser or generation.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Indeck Energy Services	No	Not registered
Response: Thank you for your comment.		
Oncor Electric Delivery Company LLC	No	Oncor does not believe that there is a reliability need for including dynamic or static reactive resources (e.g. static VAr compensators) that are not located at generating sites in this standard.
Response: Thank you for your comment.		
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	If there is a reliabiity need for synch-condensors and generators, why not SVCs for similar minimum capacity? don't they similarly impact system reliability?
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The		

Organization	Yes or No	Question 3 Comment
SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		

4. The SDT revised the Purpose of the standard in accordance with the SAR, "To improve the reliability of the Bulk Electric System by preventing tripping of generating units/Facilities due to miscoordination of generating unit/Facility voltage regulating controls, and limit functions with generator capabilities and Protection System settings."

Do you agree with the revised Purpose of the standard? If not, please provide suggested language changes in the Comment section.

Summary Consideration: The vast majority of stakeholders agreed with the revised Purpose of the standard. Topics of concern among those not in agreement included the following (# of stakeholders expressing the concern listed in parenthesis):

- **Concern that existing language limits the standard only to traditional rotating machinery.**
- **Concern that "capability" was inconsistently used.**
- **Concern that units less than 50 MVA are too small to include.**
- **Dislike "prevent tripping," suggest "reduce the potential for tripping."**
- **Concern that PRC-001 should include this standard's scope.**
- **Dislike the use of "Protection System settings."**
- **Concern that Purpose over reaches the purpose and intention of the SAR.**

The drafting team made minor changes to the Purpose in response to the concerns and suggestions provided by the stakeholders. The proposed Purpose is:

To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

Organization	Yes or No	Question 4 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The SDT does not agree with the expansion in scope that would result from the suggested change in wording. For example, this would include all transmission capacitor banks on the BES. The scope of this standard is not limited to traditional rotating machinery, but also applies to all generating Facilities, including asynchronous Facilities such as wind and solar.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		Does this SDT really believe a standard will "prevent" trippings due to mis-coordination?
Response: Thank you for your comment. The SDT agrees with your concern, and has changed the wording to that suggested by the Independent Electricity System Operator.		
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		

Organization	Yes or No	Question 4 Comment
PPL Generation	No	As stated in comment 2 for item 9 below, NERC is not being consistent in using the term "capability." It refers in other standards to that which can be achieved, not to the condition at which tripping is needed.
Response: Thank you for your comment. The intent of the standard, including the wording in the Purpose statement, is that the equipment capability be considered in the overall coordination study. Requirement R1, part 1.1.1, has been revised to clarify that protection should protect the equipment.		
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	No	Verification on unites less than 50 MVA is unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Response: Thank you for your comment. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Westar Energy	Yes	

Organization	Yes or No	Question 4 Comment
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 4 Comment
Lakeland Electric		
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	No	Replace the phrase "...preventing tripping..." with "...reducing the potential for tripping..."
Response: Thank you for your comment. The SDT agrees with your concern, and has changed the wording to that suggested by the Independent Electricity System Operator.		
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.
Response: Thank you for your comment. The SDT does not agree with the expansion in scope that would result from the suggested change in wording. For example, this would include all transmission capacitor banks on the BES. The scope of this standard is not limited to traditional rotating machinery, but also applies to all generating Facilities, including asynchronous Facilities such as wind and solar.		
Constellation Power Generation	No	Although CPG believes that the purpose of this standard is valid and accurate, it closely resembles the purpose of PRC-001 and therefore the requirements drafted in PRC-19 should be rolled into a revision of PRC-1.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The PRC-001 SDT could propose retiring PRC-019-1 as part of their process if they include the content of PRC-019 in their standard.		
Consolidated Edison Co. of NY, Inc.	No	Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.
Response: Thank you for your comment. The SDT does not agree with the expansion in scope that would result from the suggested change in wording. For example, this would include all transmission capacitor banks on the BES. The scope of this standard is not limited to traditional rotating machinery, but also applies to all generating Facilities, including asynchronous Facilities such as wind and solar.		
American Electric Power	No	We are concerned by the inclusion of "protection system settings" in how it might differ from, or be confused with, the NERC defined term Protection System. The term "generator capabilities" should be removed from the purpose statement (as well as the requirements), as it is general enough of a term to make proving compliance difficult.
Response: Thank you for your comment. The "Protection System settings" are the settings used in the Protection System. For the purpose of this standard, some of the functions of the Generator Protection System may be among those that need to coordinate with limiters and equipment capabilities. The SDT feels it is appropriate to consider both "Protection System settings" and "generator capabilities." Documentation of "generator capabilities" are usually provided by the OEM, but may be modified by the Generator Owner for specific conditions.		
Ingleside Cogeneration LP	Yes	
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy	No	Disagree strongly: It is overreach to make this a generator protection standard; the standard is not comprehensive enough to take on that task. As a result, the SDT has overstated the purpose and intent of this standard. Simple is better and appropriate. Purpose: To improve reliability through coordination of generator protection systems with unit/facility voltage

Organization	Yes or No	Question 4 Comment
		regulating limiter functions and protection.
Response: Thank you for your comment. The SDT agrees with your concern, and has changed the wording to that suggested by the Independent Electricity System Operator.		
Manitoba Hydro	Yes	
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	Yes	We do not have any real issues with the purpose statement; however, we offer an alternative to add a bit more positive spin (as opposed to preventing tripping):To improve the reliability of the Bulk Electric System by ensuring proper coordination of generating unit/facility voltage regulating controls and limit functions with generator capabilities and protection system settings.
Response: Thank you for your comment. The SDT agrees, and has revised the language based on your proposed wording for the Purpose statement.		
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indeck Energy Services	No	There is no evidence that this needs to be done to any unit less than the NERC Reportable Disturbance level for the control area.
Response: Thank you for your comment. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Oncor Electric Delivery Company LLC	Yes	

Organization	Yes or No	Question 4 Comment
Indiana Municipal Power Agency	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

5. The proposed effective dates provide a "phased-in" approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/Facilities. Do you agree with the proposed implementation schedule? If not, please provide an alternative implementation schedule, approach, and supporting information in the comments.

Summary Consideration: A majority of stakeholders agreed with the proposed phased-in approach outlined in the implementation schedule. Topics of concern among those not in agreement included the following:

- **Concern that Applicability Section 5.2.5 is missing.**
- **Suggestion that the first 20 percent be due in two years vs. one year.**
- **Concern over M1 previous test evidence requirements.**
- **Conflicting information between the standard effective date section and the implementation plan schedule.**
- **Recommendation to match MOD-026 implementation plan.**
- **Misunderstanding of one unit vs. multiple unit plant application.**

The standard drafting team made the following changes in response to the comments received:

- **The Applicability Section 5.2.5 was added, as suggested.**
- **The effective date in the Implementation Plan has been corrected to match that shown in the Applicability section of the standard.**
- **Measure M1 was modified to address the previous test evidence requirements, and now reads:**

M1. Each Generator Owner and Transmission Owner will have evidence, such as example evidence provided in PRC-019 Section G, to show that its applicable Facility voltage regulating system controls and Protection System functions are coordinated with the applicable Facility capabilities and Protection System settings as specified in Requirement R1. As applicable, this may include the following:

- **In service excitation system and voltage regulating system control, limiters and protection functions**
- **In-service generator or synchronous condenser protection system settings**
- **Generator or synchronous condenser capabilities, or**
- **Steady state stability limit.**

The coordination should include 1) verifying the in-service limiters are set to operate before the protection and the protection is set to operate before conditions cause damage to equipment assuming normal AVR

control loop and system steady state operating conditions, and 2) verifying the desired settings are applied to the in-service equipment.

The SDT did not adopt the recommendation to verify the initial 20 percent of applicable units within two years instead of one year of the effective date because it is desired to align the Implementation Plan of this standard to match the MOD-025-2 Implementation Plan. The SDT believes the elements of this standard should be performed as a precursor to performing Reactive power capability testing, specified by MOD-025-2.

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	It appears that Item 5.2.5 in the Applicability section is missing. We propose adding, "5.2.5 By the first day of the first Calendar quarter, five calendar years following Board of Trustee approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units".
Response: Thank you for your comment. The SDT has corrected this oversight.		
SPP Reliability Standards	No	The team would like to move out the initial 20% to 2 years and add a year to the following phases as well i.e 40% 3 years 60% 4 years etc. 5.2.5 seems to be missing from the standard

Organization	Yes or No	Question 5 Comment
Development Team		which doesn't include a bullet for 100% for those who need Board approval.
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		
PPL Generation	Yes	
Dominion	No	The effective date implementation schedules contained in the standard and the associated Implementation Plan do not agree. Specifically, the standard indicates one year following regulatory and/or Board of Trustee approval where as the Implementation Plan indicates two year. Additionally, the standard at Step 5.2 does not include a sub-step for 100% of applicable units.
Response: Thank you for your comment. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee		
NERC Staff	No	As written, the standard only addresses 80% compliance on generation and reactive sources that are not subject to regulatory approval. It appears that a section 5.2.5, similar to section 5.1.5, is missing from the Effective Dates section.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The SDT has corrected the oversight concerning Section 5.2.5.		
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	Yes	
Westar Energy	No	We would recommend the following implementation schedule:20% - 2 years after regulatory approval40% - 3 years after regulatory approval60% - 4 years after regulatory approval80% - 5 years after regulatory approval100% - 6 years after regulatory approval
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of application units in the Implementation Plan.		
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	In requirement R5.2 - there should be a sub-requirement R5.2.5 for 100% compliance at five calendar years?
Response: Thank you for your comment. The SDT has corrected the oversight concerning Section 5.2.5.		
Lakeland Electric		

Organization	Yes or No	Question 5 Comment
Salt River Project	Yes	
PacifiCorp	No	Measure M1 in proposed Standard PRC-019-1 requires current evidence to satisfy the coordination requirements of Requirement R1, Section 1.1, plus one previous dated set of evidence demonstrating the latest coordination review has been performed within the intervals prescribed in Requirement R1, Section 1.2. The latter category of evidence may not be available immediately upon the effective date of this proposed standard. The implementation plan should clarify how this Measure will be addressed during the phased-in implementation schedule.
Response: Thank you for your comment. The SDT agrees, and Measure M1 has been changed to address your concern.		
South Carolina Electric and Gas	No	There seems to be a mistake on the Implementation Plan versus the Standard. The implementation plan states two years for the first 20% of applicable units and the standard states one year. Please clarify this inconsistency.
Response: Thank you for your comment. The SDT has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	No	Some of the requested data will reside in places not familiar to smaller entities and may require the use of consultants. The SDT may want to consider giving 2 years until the first 20% compliance level is reached because it will take time to set up a program.
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2.		
New York Independent System Operator		

Organization	Yes or No	Question 5 Comment
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	For Cowlitz, this would be acceptable. However, Cowlitz only owns a few generation plants. We must defer to those who own many plants.
Response: Thank you for your comment.		
Xcel Energy	Yes	
Lakeland Electric		
Exelon	No	There is a conflict with the implementation periods stated within the body of Standard PRC-019-1 and the associated Implementation Plan. PRC-019-1 Section 5 Effective Date Step 5.1.1 states "(b)y the first day of the first calendar quarter, one year following applicable regulatory approval ... " [emphasis added]; however, the Implementation Plan states the Effective Date is "(t)he first day of the first calendar quarter two years following applicable regulatory approval ... " [emphasis added].Exelon requests that the implementation period be 2 years following regulatory approval. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). An implementation period of 2 years will allow for any modifications to existing equipment be completed during a refueling outage.
Response: Thank you for your comment. The conflict between the Implementation Plan and the body of the standard has been corrected. The SDT does not believe the requirement to have 20 percent of applicable units compliant within the first year is an undue burden. For the example noted, the unit could be verified with the last 20 percent of Exelon's fleet, which gives over four years to comply with the standard.		
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission		

Organization	Yes or No	Question 5 Comment
Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Electric Power	No	In light of the many other changes to standards currently proposed, and their implementations, AEP would suggest an additional year to the proposed implementation schedule to ensure a successful adaptation to PRC-019-1.The effective date for the 20% compliance milestone is inconsistent between the draft standard and the implementation plan, with one document allowing one year for compliance and the other allowing two years.
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
Ingleside Cogeneration LP	Yes	The five year phased-in validation of settings is sufficient for Ingleside Cogeneration LP.
Response: Thank you for your comment.		
Wisconsin Public Service		

Organization	Yes or No	Question 5 Comment
Corp		
GE Energy		
ISO New England		
GenOn Energy	Yes	
Manitoba Hydro	No	-MH recommends that the effective dates for this standard be identical to MOD-026. This will allow entities to schedule all work and required outages simultaneously.
Response: Thank you for your comment. The SDT believes the elements of this standard should be performed as a precursor to performing Reactive power capability testing, as specified in MOD-025-2. The Implementation Plan is designed to match that of MOD-025-2.		
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator		
Gainesville Regional Utilities	Yes	
Ameren	Yes	Yes, only if settings need to be verified. No if testing needs to be done to verify settings.
Response: Thank you for your comment. The standard does not require testing. It only requires that the settings that are used for determining coordination have been verified to be the settings that are in service.		
Indeck Energy Services	No	For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single

Organization	Yes or No	Question 5 Comment
		unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
Response: Thank you for your comment. The implementation plan is based on an entity's total number of applicable units, not the number of units installed at a plant. An entity that owns only one unit would have to be in compliance after one year, not five.		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

6. **Do you agree that the evidence, documents, and functions listed in Section G are sufficient for giving the Generator Owner/Transmission Owner examples of how the coordination can be demonstrated? If not, please provide suggested language changes to the Measure and supporting information in the Comment section.**

Summary Consideration: Specific changes were made to Section G of the standard based on comments received. These changes include:

1. **Providing example diagrams using nominal voltage and frequency as basis.**
2. **Correcting the SSSL radius calculation.**
3. **Information previously listed in the "under-excited limiters or minimum excitation limiters" and the "over-excited limiters or maximum excitation limiters" section has been combined into a bulleted list section.**
4. **The SDT changed "protective" to "protection" within the standard to be consistent with Section G.**
5. **The SDT added another reference document for use in calculation of SSSL.**

Several commentators were concerned that Section G prescribed a method for illustrating coordination of AVR limiter/protection functions with other Protection Systems. The SDT agrees there are several ways of demonstrating coordination, and does not prescribe a particular method. Any protective function that is enabled should be evaluated for proper coordination.

The SDT considered the request to remove distance relay and volts/hertz relay elements from the standard. The SDT believes these elements should remain in the standard because (a) the distance element should illustrate coordination with field forcing controls of the AVR, and (b) the volts per hertz function can operate with the unit on-line under certain operating conditions.

Organization	Yes or No	Question 6 Comment
LG&E and KU Energy		
Northeast Power	Yes	

Organization	Yes or No	Question 6 Comment
Coordinating Council		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee	No	The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency.
Response: Thank you for your comment. The SDT has revised example diagrams using nominal voltage and frequency as basis.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	While the team agrees with this evidence, some of the older units in the system may not have this information readily available.
Response: Thank you for your comment.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	We believe that the tutorial like language in Section G is not appropriate for a standard. There is an abundance of material available describing the coordination of generator protection equipment, such as textbooks, IEEE tutorials and even NERC tutorials. We believe referencing the documents could be appropriate and helpful. Even though the diagrams are listed as examples, we believe they might be interpreted a recipe to be followed.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. The SDT believes Section G provides applicable entities information on how compliance may be demonstrated without prescribing how to accomplish compliance. Entities may demonstrate compliance in ways other than those offered as examples in Section G.		
Santee Cooper		
PPL Generation	No	
Dominion	Yes	
FirstEnergy		At the moment we do not have comments on the proposed measures. We will review the proposed measures on the next draft and provide out input.
Response: The SDT will respond when comments are provided.		
SERC Dynamics Review Sub-committee		
NERC Staff	No	The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency.Further, Section G should address the system concerns described in Table 2 of the SPCS Technical Reference Document “Power Plant and Transmission System Protection Coordination,” for the generator protection functions that must be coordinated.
Response: Thank you for your comment. The SDT has revised the example diagrams using nominal voltage and frequency as basis. The SPCS Technical Reference Document addresses issues regarding generator and system protection coordination that are beyond the scope of PRC-019-1. At the same time, some of the coordination required in PRC-019-1 is not covered by the SPCS document. For example, the Loss of Field (40) function in Table 2 does not discuss coordination with the under-excitation limiter nor the steady-state stability limit.		
Public Service Enterprise Group	Yes	
SERC Generation sub-		

Organization	Yes or No	Question 6 Comment
committee		
ACES Power Members	Yes	
Arizona Public Service Company	No	30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Response: Thank you for your comment. We believe this comment refers to a different standard – probably MOD-025-2.		
Westar Energy	Yes	Examples for older units, where the information in the current examples are not readily available, could be included.
Response: Thank you for your comment. The examples provided in Section G are representative of both older units and newer units. Entities may demonstrate compliance in ways other than those offered as examples in Section G.		
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	No	This item needs to coordinate with PRC-001 (System protection Coordination) and the future PRC-023-1 (generator loadability) standard currently under development. Section G indicates a distance relay (21) but does not indicate any timers that would be coordinated with the transmission provider. Propose removing this protective relay from Attachment 2.
Response: Thank you for your comment. The SDT believes the distance function (21) may need to be coordinated with excitation limiters and equipment capabilities, and should be evaluated if it is applied to a generating Facility. Coordination of that protective function with the transmission system is addressed by PRC-001 and PRC-023, as mentioned.		
Lakeland Electric		
Salt River Project	Yes	

Organization	Yes or No	Question 6 Comment
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.		
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	Cowlitz needs to confer with its consultant to form a more informed opinion. However, it appears to be reasonable.
Response: Thank you for your comment.		
Xcel Energy	Yes	
Lakeland Electric		
Exelon	No	In addition to the methodology listed, a provision should be allowed to use an alternative acceptable methodology that meets the intent of the Standard such as a methodology that uses impedance locus for loss of field for settings for the loss of field relays.Attachment G second formula is incorrect and should be corrected as follows:R = V2 g/2*(1/Xs+1/Xd) (Divide by 2)
Response: Thank you for your comment. The methodology listed in the example is not all-inclusive. The wording in Section G specifically states		

Organization	Yes or No	Question 6 Comment
"…the evidence of coordination associated with Requirement R1 may be in the form of …" The SDT has corrected the error in the formula for R.		
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	No	The following should be added to the list in Section G:1. under-excited limiters or minimum excitation limiters 2. over-excited limiters or maximum excitation limiters.
Response: Thank you for your comment. While all of the items identified were contained in the posted standard, the SDT has revised the standard by moving the example items to be considered for coordination from the list section referenced into a bulleted list section.		
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	No	CPG believes that engineering documents detailing the coordination of the these components should be sufficient in lieu of coordination plots requiring software that is not commonly used by generators.
Response: Thank you for your comments. The SDT agrees there are several ways of demonstrating coordination, and does not prescribe a particular method.		
Consolidated Edison Co. of NY, Inc.	Yes	

Organization	Yes or No	Question 6 Comment
American Electric Power	No	There appear to be inconsistencies between the standard and appendix G. the standard uses the term “protective system settings” and “protection system settings” while the appendix uses the term “protection function”.
Response: Thank you for your comment. The SDT has changed “protective” to “protection” within the standard.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP agrees with the concept of establishing a mode of operation that allows voltage regulators and limiters the first opportunity to deal with a voltage transient well before the corresponding Protection Systems are activated. However, we are concerned that protective relay settings must be always set in accordance with the Steady State Stability Limit (SSSL) as defined by NERC. There may be factors that are more limiting which require more sensitive settings - which should be acceptable if demonstrated on a P-Q, R-X or similar graph.
Response: Thank you for your comment. The standard does not prescribe that the protective relay settings must always be set in accordance with the SSSL. The SDT agrees that there may be limiting factors requiring more sensitive Protection System settings than required by the SSSL. Setting Protection Systems to the most limiting factor is acceptable.		
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	Yes	
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator		
Gainesville Regional Utilities		
Ameren	No	(1)Volts per hertz and stator overvoltage protection are more applicable during unit start-up, not running conditions, where the system maintains the voltage and frequency. These should be eliminated. (2) The standard needs to be clear on what relay elements need to be included if enabled. (3) The standard needs to be clear on how to plot the diagrams to incorporate operating voltage. For example the generation is most stable while maintaining maximum permissible voltage and producing the most VAr's possible. Therefore should the plot be at maximum voltage of 1.05pu. (4) It would be helpful to have some reference for where the development of the Steady State Stability Limit equations in the draft standard could be found. None could be found on the NERC website. We are concerned that the method proposed for calculating steady state stability limits does not include sufficient conservatism.
Response: Thank you for your comment. (1) The SDT believes that it is possible to encounter volts per hertz conditions during normal operation, so this needs to be evaluated. (2) The SDT believes any protection functions that are enabled should be evaluated for proper coordination. (3) The SDT does not prescribe what voltage or frequency to use when evaluating coordination. The entity performing the evaluation can choose the voltage and frequency value to use. (4) The SDT has added a technical reference regarding SSSL equation development to the standard.		
Indeck Energy Services		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

7. Do you agree with the data retention language listed in the Compliance section of the draft standard? If not, please comment and provide alternative data retention language.

Summary Consideration: Forty-six stakeholders agreed, 27 stakeholders disagreed, and 18 stakeholders had no opinion.

Three stakeholders were concerned that the TO might be required to retain compliance data for generation equipment that it does not own. The applicability requirements in the draft standard have been clarified.

Eleven stakeholders were concerned that the data retention requirements were unclear, especially as the standard is being phased in. Stakeholders were also concerned that data retention requirements might be excessive. The SDT revised the Measure M1 and the data retention requirements for clarity and to be consistent with the NERC Compliance Process Bulletin #2011-001.

Organization	Yes or No	Question 7 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
Response: Thank you for your comment. The equipment owner has responsibility for data retention. If a Transmission Owner owns a synchronous condenser, then the Transmission Owner is only required to retain compliance data for that equipment. The SDT agrees the Application section		

Organization	Yes or No	Question 7 Comment
needed to be clarified, and has modified Section 4.1.2 to state that the standard only applies to Transmission Owners that own synchronous condensers.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	For new units or units that haven't changed you would not have prior data to provide. The drafting team may need to think about rewording to address this issue.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		

Organization	Yes or No	Question 7 Comment
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	No	Section 1.2 of the Compliance section is missing a time frame for data retention. Timeframes consistent with CEA routine audit cycles should be added to this section.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	No	The data retention for M1 may not be consistent with NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. In that bulletin, NERC appears to require some level of evidence for the entire audit period.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Arizona Public Service Company	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company	No	Only the last two documentation sets are needed to prove the intervals are being met. ALL previous sets are not necessary. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Tennessee Valley Authority GO	Yes	
Luminant Power	No	Once coordination is completed, the retention shall be until the unit is retired or a system change has occurred, plus any coordination document that was in effect during the current audit cycle.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Lakeland Electric	No	The word “prior” lacks specificity. Proposed: “...shall retain the latest evidence of compliance with Requirement R1, Measure M1 dating back to most recent audit period.”
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric	Yes	

Organization	Yes or No	Question 7 Comment
Cooperative, Inc.		
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	
Lakeland Electric		
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	No	Initial compliance, within the first audit period, should be based on one evidentiary document set. Subsequent compliance, after the first audit period, may include the most current and the previous evidentiary document set.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		

Organization	Yes or No	Question 7 Comment
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
Response: Thank you for your comment. The equipment owner has responsibility for data retention. If a Transmission Owner owns a synchronous condenser, then the Transmission Owner is only required to retain compliance data for that equipment. The SDT agrees the Application section needed to be clarified, and has modified Section 4.1.2 to state that the standard only applies to Transmission Owners that own synchronous condensers		
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	No	The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a

Organization	Yes or No	Question 7 Comment
		considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
Response: Thank you for your comment. The equipment owner has responsibility for data retention. If a Transmission Owner owns a synchronous condenser, then the Transmission Owner is only required to retain compliance data for that equipment. The SDT agrees the Application section needed to be clarified, and has modified Section 4.1.2 to state that the standard only applies to Transmission Owners that own synchronous condensers		
American Electric Power	Yes	
Ingleside Cogeneration LP	Yes	
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	Yes	
Duke Energy	No	Electronic documentation of coordination efforts should be considered accecptible as long as a revision history is maintained. Past history is not significant to present/future reliability. Only the presentation documentation of coordinations is needed along with proof that the results have been implemented. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Lincoln Electric System		

Organization	Yes or No	Question 7 Comment
CPS Energy		
Independent Electricity System Operator	No	We interpret the wording “shall retain the latest and the prior evidence of compliance with Requirement R1, Measure M1” to mean the evidence for the last and the one before last compliance assessments. We question the need to keep the two sets of evidence. Keeping only the evidence for the last compliance assessment would suffice.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Gainesville Regional Utilities	Yes	
Ameren	No	Retaining studies for 10 years seems unreasonable and could lead to confusion. Retaining data from previous audit seems reasonable to assure studies are being done every 5 years. Regarding R1.1.2, in order to limit the need to take unnecessary outages, which may be required to verifying settings, verification of settings should be limited to a one time only, upon installation or setting change.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Indeck Energy Services	No	One year history should be sufficient. It's about the verification, not keeping paper or electronic records forever.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	No	IMPA is answering this question in conjunction with question 9. IMPA believes that the study should happen initially and only if a change is made or equipment is modified. If using this approach, the previous evidence and the new evidence should be retained.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

8. Are you aware of the need for any regional variances to this standard? If yes, please explain in the comment section.

Summary Consideration: By a large majority, stakeholders do not believe a regional variance is needed. There are very few instances known that might justify having a regional variance. The four stakeholders answering "yes" to this question did not provide specific reasons why a variance might be needed.

Organization	Yes or No	Question 8 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	No	
NERC System Protection and Control Subcommittee	No	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	

Organization	Yes or No	Question 8 Comment
SPP Reliability Standards Development Team	No	
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	
Santee Cooper		
PPL Generation	No	See comment 2 for item 9 below.
Dominion	No	
FirstEnergy	No	We are not aware of the need for a variance at this time.
Response: Thank you for your comment.		
SERC Dynamics Review Sub-committee		
NERC Staff	No	
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members		

Organization	Yes or No	Question 8 Comment
Arizona Public Service Company	Yes	
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	No	
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and	No	

Organization	Yes or No	Question 8 Comment
Transmission, In.		
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation		
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	
Constellation Power Generation	No	
Consolidated Edison Co. of	No	

Organization	Yes or No	Question 8 Comment
NY, Inc.		
American Electric Power	No	AEP is not currently aware of any need for regional variances to this standard.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	No	
Duke Energy	Yes	There may be regional variations in regional critical size criteria.
Response: Thank you for your comment. The SDT cannot respond if a specific regional variation concern is not identified.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren	No	

Organization	Yes or No	Question 8 Comment
Indeck Energy Services		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

9. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain in the Comment section.

Summary Consideration: The drafting team received many suggestions for improvements to the standard. Several stakeholders commented on the Applicability section, requesting clarity with regard to Transmission Owners' obligations, threshold equipment nameplate ratings, or capacity factor exemptions. The GVSDT revised the Applicability section to clarify that only Transmission Owners owning synchronous condensers are specified as applicable entities in the standard. The applicability section specifies the same equipment nameplate rating thresholds defined in the Compliance Registry criteria. The standard does not allow other exemptions.

Several stakeholders commented on various aspects of Section G. The GVSDT considered these comments and made minor changes for clarity.

A few stakeholders requested changes to Measure M1 and the Data Retention section to clarify what evidence is necessary during the implementation period and also following changes requiring a coordination review. The GVSDT revised the language to clarify intent and also satisfy the NERC Compliance Guideline #2011-001.

A few stakeholders stated Requirement R1 could be interpreted to require protection settings that operate within the equipment capability. The GVSDT revised the R1 language to clearly state that protection must be set to prevent equipment damage.

A couple of stakeholders indicated the standard lacked clarity on which protective functions must be coordinated with limiters and equipment capability. In response, the GVSDT stated all in-service protective functions that might operate during steady-state system conditions must be evaluated and opted not to revise the standard.

Two stakeholders indicated the standard should require coordination be evaluated with the strongest transmission line out of service. The GVSDT believes doing this would add a great deal of complexity to the process without a corresponding gain in reliability.

Two stakeholders indicated the emphasis on coordination would prevent proper protection of the equipment. The GVSDT disagrees.

Two stakeholders took issue with the terms "in service," and "Point of Interconnection." The GVSDT maintained the term "in-service" (as defined in Footnote 1) in the standard and removed the term "Point of Interconnection" from the standard.

One stakeholder identified inconsistencies between the Title, Purpose, and Requirement R1 language. These inconsistencies were resolved.

One stakeholder identified the discrepancy between the Comment Form and the standard regarding synchronous condenser applicability nameplate rating threshold, and also noted that part of the Effective Date section was missing. In response, the GVSDT provided explanation for the discrepancy identified, and corrected the Effective Date section.

A few individual comments were received requesting the standard be revised to 1) include static var compensators, 2) specify a complete list of elements to be coordinated in R1, 3) change the coordination review time frame following a change in settings or equipment, and 4) add a requirement to activate and set excitation limiters. The GVSDT does not agree the standard would be improved by incorporating these suggestions.

Organization	Yes or No	Question 9 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	Related to the "Examples of Coordination", the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Response: Thank you for your comment. The diagrams in Section G are optional and provided as examples for industry. It is expected more than one diagram would be needed to demonstrate coordination for most units. The GVSDT has revised Section G to clarify this point.		
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	Based on the Requirements and Measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only

Organization	Yes or No	Question 9 Comment
		apply to Transmission Owners that own synchronous condensers. If that is the case, Section A-4.1.2 should be re-written as follows: "Transmission Owner that owns a synchronous condenser." This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined.Do the requirements in this new standard overlap or duplicative with PRC-001 R3 and R5?
Response: Thank you for your comment. The SDT agrees proposed language for Section 4.1.2 will improve standard clarity, and has modified the standard accordingly.		
NERC System Protection and Control Subcommittee	Yes	Requirement R1: The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the generating unit, such as the list in Section G. Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions.Requirement R1, part 1.1.2: The word "check" is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as "Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment."Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project the Generator Owner should be required to verify coordination prior to placing the revised equipment or settings in-service.The SSSL derivation should consider the impact of system strength (e.g., strongest transmission line source out-of-service), generation saturation, and AVR status to assure an appropriately conservative limit.Implementing a UEL based on the steady-state stability limit may prevent under-excited operation, which would otherwise be stable and useful in managing system conditions (such as during system restoration activities or in lightly-loaded areas that need to sink reactive power to control voltage or synchronizing a generator to a long line).Where the Generator Owner and Transmission Owner are separate entities, there is difficulty for the Generator Owner to obtain system impedance information and

Organization	Yes or No	Question 9 Comment
		keep it up to date as the transmission system may be re-configured during on-going operations; this information is necessary to represent the SSSL.The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.
Response: Thank you for your comment. The SDT believes all in-service protection functions for a generating unit or synchronous condenser should be evaluated for coordination with the limiters, capabilities and protection under steady state conditions at nominal voltage and frequency. **This standard does not require evaluating coordination under transient conditions.** **The SDT believes that all protection functions, including generator backup distance and backup overcurrent, can be coordinated with the limiters and capabilities, as shown on Attachment 2, when considered under steady-state conditions using nominal voltage and frequency.** **The recommendation to demonstrate that the settings used in the coordination evaluation are the same settings applied to the in-service equipment is addressed by Measure M1.** **The SDT agrees that removing lines from service will affect the SSSL characteristic, however this is normally a fairly small change since the equivalent transmission system; impedance is much smaller than the step-up transformer impedance. Proper coordination would allow enough margin between the SSSL with all lines in service and the protection characteristics to allow for minor variations in the SSSL.** **The SDT does not believe a Transmission Owner would refuse to provide a Generator Owner with information requested for a reliability reason.** **The SDT agrees that the primary reason for Protection Systems is to protect power system equipment. The coordination philosophy described is essentially a restatement of that found in Section 3.5 of the NERC Power Plant and Transmission System Protection Coordination document.**		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	Consider adding a note to Attachment 1, which states that the type of D curve should be specified (i.e. based on the data reported per the MOD-010 standard, the data reported per the MOD-025-2 standard, or some other basis).
Response: Thank you for your comment. The SDT does not believe it should prescribe specific evaluation evidence. It is anticipated the equipment owner will utilize information obtained per MOD-010 for the coordination evaluation specified.		
SPP Reliability Standards	Yes	It seems there is room for clean up in the posted standard.

Organization	Yes or No	Question 9 Comment
Development Team		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	
Santee Cooper		
PPL Generation	Yes	PPL Generation suggests the following changes:1. Consider making this standard applicable to generation facilities having a capacity factor for the past three years averaging over 10%. The basis for this request: As presently written this Applicability would require compliance for a small, emergency genset if located in a baseload facility interconnected > 100 kV. 2. In Requirements R.1, R1.1.1, R1.2 and elsewhere where the term "capability" is used, consider using the term "trip limit". As currently written, it appears that Requirement 1.1.1 is semantically misdirected in requiring protectives to be set below equipment capabilities. A capability is what the unit can actually do (ref. MOD-024 and 025). It is not the limit beyond which damage, instability or other problems may occur. A unit with a 875 MVA GSU and 900 MVA generator, for example, may have a real power capability of only 750 MW based on boiler and turbine limitations. It is not possible to have trips set below a unit's capability, unless PRC and MOD apply different meanings for this term, which would not be suitable.Confusion may be caused by generator D-curves also being called “capability curves,” but here also one would not want to require that generator never be operated at the D-curve value.
Response: Thank you for your comment. The Applicability section of this standard correlates with the applicability section of MOD-025-2 because it is anticipated the coordination evaluation performed for PRC-019-1 will be accomplished before the Reactive capability testing required by MOD-025-2. Requirement 1, part 1.1.1, has been revised to address concern with the coordination of protection and capability. D-curves are one way to define equipment capability (and are often called “ Reactive capability curves”).		
Dominion	Yes	1) the phrase “Generating equipment”, in the 3rd bullet of R1, be changed to “Generator” to be consistent with the usage under bullets 1 & 2. 2) The title and purpose of the document do not address synchronous condensers as addressed in Requirement R1; 3) if the standard includes synchronous condensers, why are static VAR compensators not included? The

Organization	Yes or No	Question 9 Comment
		following bullets under R1 are too generic. Should specifically outline required parameters.ï‚•ï€ In-service 1excitation system and voltage regulating system control, limiters and protection functions o In-service generator or synchronous condenser protection system settings o Generating equipment or synchronous condenser capabilities o Steady state stability limit We recommend replacing the bullets with the following: o Generator or syn. Condenser capability curves. o Steady state stability limit. o Loss of field zone 1. o Loss of field zone 2. o Loss of field trip. o Under excitation limiter. o Over excitation limiter. o Power factor line. o Backup over current settings. o Instantaneous field current trip. o Instantaneous field current limit. o Volts per hertz.
Response: Thank you for your comment. (1)The SDT has revised R1 based on your suggestion. (2) The SDT has revised the Title and Purpose based on your suggestion. (3) The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard. As Pepco states in their comment to Question 3: "SVC protective devices are set assuming the full bank is in service. Synchronous machines, however, are a different story entirely. The quantity of Reactive power produced by, or drawn into, the machine is a function of the machine field current. In an under-excited condition, the unit may loose synchronism or trip via loss of field protection, unless the voltage regulator (min. excitation limiter) is properly set and coordinated with the machine's capability and protective devices. Similarly, excessive Var output and/or terminal overvoltage caused by over-excitation of the field can result in equipment damage or unit tripping, unless the voltage regulator is properly set and coordinated with the machine's capability and protective devices." In addition, IESO points out in their response to Question 3: "The SVCs serve quite different purpose and react to system conditions quite differently compared to their generator/synchronous condenser counterparts." (4) The bulleted list in R1 are categories that need to be considered when performing coordination evaluation, and is not intended to be a complete list of specific functions.		
FirstEnergy	Yes	M1 requires that the GO will have evidence that "…voltage regulating system controls and protection functions are coordinated with the generating unit and generating Facility capabilities and protective system settings applied to in-service equipment as specified in Requirement R1, Section 1.1, and one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2." For the first verification cycle this would require that units would have to prove compliance as much as 4 years before the standard became enforceable. This is akin to setting up a traffic camera in a 35 mph zone in March, changing the speed limit in that zone to 25 mph in July, and going back and writing tickets for every car that exceeded 25 mph from March through June. This needs to be clarified. Requirement R2 (shown as 1.2 in the standard) should have a violation risk factor of MEDIUM instead of HIGH. Furthermore, it seems that the phrase "within 90 days of making a change to the generating equipment, voltage control limiter settings, or protective function settings that would affect the coordination" is not necessary because a change to equipment

Organization	Yes or No	Question 9 Comment
		setting would already require coordination per Requirement R1. We suggest removing this part of 1.2 (or R2).
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001. With respect to your suggestion to remove Requirement 1, part 1.2, the SDT disagrees and believes verification of coordination needs to be performed in a timely manner following a change to equipment or settings.		
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the generating unit, such as the list in Section G.This should be consistent with protection coordination described in the SPCS Technical Reference “Power Plant and Transmission System Protection Coordination.” Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions.Requirement R1, part 1.1.1: The standard emphasizes preventing tripping of generating units and generating facilities due to miscoordination. Another aspect of coordination is to coordinate the protections and controls to coordinate with the equipment capability. Without guidance or direction, the standard could have the unintended consequence of overly conservative settings that limit the ability of the facilities to respond to system disturbances, or inadvertently create a common-mode failure trip point across a generation fleet.Requirement R1, part 1.1.2: The word “check” is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as “Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment.”Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project, the Generator Owner or Transmission Owner should be

Organization	Yes or No	Question 9 Comment
		required to verify coordination PRIOR to placing the revised equipment or settings back in-service. It is important to note that protection setting changes on the transmission system may necessitate generating unit protection setting changes which in turn require a review of coordination with the generating unit or plant voltage regulating controls. While coordination between the transmission system and generating unit protection settings is outside the scope of this standard it is important that this coordination is required by in a reliability standard.The examples emphasize steady-state limits and capability curves without mention of the short-term generating unit capabilities. Proper coordination should also apply to transient response of the generating unit and its associated limiters to meet the reliability objective of this standard. Focusing examples on steady-state coordination may be misleading and result in miscoordination for transient events. Of particular concern is the transient response of exciters in field-forcing during system disturbances; loss of reactive support from generation during such events can be catastrophic and lead to cascading.The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.

Response: Thank you for your comment. The SDT believes all in-service protection functions for a generating unit or synchronous condenser should be evaluated for coordination with the limiters, capabilities, and protection under steady-state conditions at nominal voltage and frequency.

This standard does not require evaluating coordination under transient conditions.

The SDT believes that all protection functions, including generator backup distance and backup overcurrent, can be coordinated with the limiters and capabilities, as shown on Attachment 2 ,when considered under steady-state conditions using nominal voltage and frequency.

The recommendation to demonstrate that the settings used in the coordination evaluation are the same settings applied to the in-service equipment is addressed by Measure M1.

With regard to the suggestion to include transient response in the coordination evaluation, the SDT believes the function of the limiters is to prevent operation in regions that would damage the equipment during transient conditions, and that proper coordination of limiters with protection will prevent improper tripping of the equipment.

The SDT agrees that removing lines from service will affect the SSSL characteristic, however this is normally a fairly small change since the equivalent transmission system impedance is much smaller than the step-up transformer impedance. Proper coordination would allow enough margin between the SSSL with all lines in service and the protection characteristics to allow for minor variations in the SSSL.

Organization	Yes or No	Question 9 Comment
The SDT does not believe a Transmission Owner would refuse to provide a Generator Owner with information requested for a reliability reason. **The SDT agrees that the primary reason for Protection Systems is to protect power system equipment. The coordination philosophy described is essentially a restatement of that found in Section 3.5 of the NERC Power Plant and Transmission System Protection Coordination document.**		
Public Service Enterprise Group	Yes	The SDT should review R1. As it reads now, the phrasing of the first paragraph makes it difficult to understand what equipment is included for generator units and what is included for synchronous condensers.
Response: Thank you for your comment. The SDT has revised R1.		
SERC Generation sub-committee		
ACES Power Members	Yes	In part 4.2.3 of the Applicability section, the phrase "regardless of size included in a Transmission Operator's restoration plan" should be struck. It is redundant with definition of Blackstart Resource.
Response: Thank you for your comment. The SDT believes it is necessary to duplicate Registry criteria language in the applicability section to clarify that the standard is applicable to other equipment in addition to synchronous condensers.		
Arizona Public Service Company	Yes	
Westar Energy	No	
Southern Company	Yes	1) The last sentence of Measure M1 is not needed. There is no need to require evidence of the change implemetation, only coordination verification is needed. The requirement for documentation of change identification or implementation is not part of Requirement R1. 2) In several places in the posting documents there is a descrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 3) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 4) Section 5.2.5 is missing from effective date in the draft standard.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. (1) The measure supports evidence needed to demonstrate compliance with the 90-day requirement specified in R1.2. Regarding comments (2), (3), (4) Noted, discrepancies have been corrected.		
Tennessee Valley Authority GO	Yes	We recommend that the minimum unit rating to be applicable to this standard should be 75 MVA, and the aggregate plant size to be applicable should be 100 MVA.
Response: Thank you for your comment. The Applicability section of the standard is based on the Registry criteria, and the SDT does not have sufficient technical justification to deviate from this criteria.		
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	Yes	In regards to Measure 1 it should be clarified that only the latest coordination review will be needed for the first 5 years after the standard is implemented and only after 10 years will the entity be required to show both latest and prior evidence of compliance for 100 % of the applicable units. As stated, it looks like the standard would require the entity to verify the existence of coordination twice on 20% of the applicable units in the first year to show evidence of a latest and prior coordination for those units. If an entity were to be audited 3 years after the effective date of the standard, they would have to show coordination of 60% of the applicable units and should not be required to show a prior documented coordination since a 5 year interval would place the prior coordination possibly before the effective date of the standard. This would also apply in the situation of a newly built applicable unit in which there would be no prior evidence available; only the latest.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
APS		being intentionally left blank (no answer to be provided)

Organization	Yes or No	Question 9 Comment
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	Yes	Cowlitz understands the difficulty the SDT is under. Although the base line of applicability is in question, this Standard is justifiable and will not present too great a burden to comply with.
Response: Thank you for your comment.		
Xcel Energy	No	
Lakeland Electric		
Exelon	No	
American Wind Energy Association	No	
Tacoma Power		None
Georgia Transmission Corporation		
Austin Energy	No	

Organization	Yes or No	Question 9 Comment
Wisconsin Electric	Yes	1. R1.2 needs to be clarified, and more time allowed. The phrase, "within 90 days following the identification or implementation of systems, equipment, or setting changes..." is vague, and should be replaced with "within 120 days of modifications made to systems, equipment, or setting changes...". The requirement should clarify that the clock starts 120 days after the date that the affected generator returned to service following the modifications. 2. It is not clear how wind generators can be subject to this standard. The information in Section G does not relate to wind machines.
Response: Thank you for your comment. (1) The SDT believes that 90 days is sufficient time to perform a coordination evaluation, and is an appropriate time frame that supports reliability. The SDT believes current language with respect to "starting the clock," is appropriate for covering the possible scenarios. (2) The standard is technology neutral. The information in Section G does not necessarily apply to a particular type of technology. The equipment owner is responsible for providing appropriate compliance evidence.		
Great River Energy		
BC Hydro	Yes	The note in section G may have to be revisited. The main issue is that active excitation limiters can prevent a unit from unneccessary tripping during system transients. The standard should encourage activation and proper setting of avaiable excitation limiters
Response: Thank you for your comment. The SDT believes it is beyond the scope of this standard to recommend additional practices.		
Northeast Utilities	Yes	Related to the "Examples of Coordination", the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Response: Thank you for your comment. The diagrams in Section G are optional and provided as examples for industry. It is expected more than one diagram would be needed to demonstrate coordination for most units. The GVSDT has revised Section G to clarify this point.		

Organization	Yes or No	Question 9 Comment
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	Yes	Related to the “Examples of Coordination”, the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Response: Thank you for your comment. The diagrams in Section G are optional and provided as examples for industry. It is expected more than one diagram would be needed to demonstrate coordination for most units. The GVSDT has revised Section G to clarify this point.		
American Electric Power	Yes	Measure 1 states the need for “one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2.”, yet this would not be required by the standard until five years following the initial coordination.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp		
GE Energy		The fourth bullet in Part G “Reference,” paragraph beginning with “Equipment limits,”, page 6: The word “stator” should be removed, in order to make the over voltage protection limits applicable to non-synchronous machines.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. The SDT has revised language accordingly.		
ISO New England		
GenOn Energy	Yes	In some ways, the requirements are too subjective in determining what protection and limiters are subject to coordination. In other ways, the standard provides insufficient or contradictory requirements in defining how coordination is achieved, even for well established protection practices. It is difficult to define all-inclusive coordination principles with so many variables in a simple straightforward standard. As written, the standard is a compliance risk to the applicable entities based upon future arbitrary and subjective interpretation by compliance organizations. Vivid examples are provided in Attachment 1. Loss-of-Excitation Zones 1 & 2 does not “coordinate” with the Steady State Stability Limit. In the diagram of the generator capability curve, SSSL is reached prior to the Loss-of-Excitation protection, contrary to R1.1.1, requiring the protection to operate ahead of the SSSL. Also, Loss-of-Excitation Zones 1 & 2 exceeds the generator capability curve, and does not fulfill R1.1.1 that requires protection to operate before conditions exceed equipment capabilities. Other variables with indirectly relationships are subject to future interpretation. A generator stator may have overvoltage protection set at 118% with a 2 second time delay, allowing it to meet PRC-024-1 ride through capability. Overvoltage protection also has a correlation to field current limiters. To insure and demonstrate absolute “coordination” with a field current limiter under all circumstances, it may be necessary to reduce the field current limit. The move will be counter productive to system performance in most transient conditions, but may be required to insure “coordination.”The SDT should make specific requirements of defined scope rather than broad, subjective, and open-ended requirements, i.e. 1) Volts/Hz limiters shall coordinate with Volts/Hz protection, 2) Under excitation limiters shall coordinate with steady state stability limits and loss-of-field protection, and 3) field current limiters shall coordinate with field current capability. The standard should exclude statements that the protection must operate before conditions exceed equipment capability. It will be difficult to provide definitive evidence of compliance for the use of many protection elements on older equipment with no documentation of equipment capability to withstand conditions such as Volts/Hz. If a generating unit is rated for +/- 5% terminal voltage, how is the generator’s overvoltage withstand capability demonstrated to PRC-024-1 criteria. In a compliance world of absolutes, Generator Owners may not be allowed to use general “rules of thumb” when coordinating protection. In ways that are counterproductive to reliability and equipment protection, Generator Owners could end up removing protection

Organization	Yes or No	Question 9 Comment
		elements when it cannot be demonstrated that it operates before the condition exceeds equipment capabilities.Calculation of the steady state stability limit requires the transmission system Thevenin equivalent impedance. Therefore, it is necessary for the standard to require Transmissions Owners to provide Generator Owners this impedance within 30 days of request. Likewise, the allocated time for Generator Owners to perform coordination studies should increase by 30 days or more to 120 days.In R1.2, a five year coordination study interval is an unnecessarily short duration for generating units without significant changes in the generator protection or an AVR replacement. A company with 150 generating units will average 2.5 coordination studies per month on a non-stop continuous rotation. Ten years is a more appropriate cycle for a coordination study on a unit with no changes. The wording used to trigger an examination should be specific and defined, rather than the ambiguous and nondescript statement of “changes that are expected to affect this coordination.” To meet compliance, it will be necessary to expend needless effort for the possible interpretations of “changes” that otherwise will have little or no impact for the intent or purpose of this standard. Suggest rewording R1.2, “Each Generator Owner or Transmission Owner shall verify the coordination indentified in Requirement R1 at least once every ten years or within 120 calendar days following modifications impacting coordination when the following activities occur: 1) a change in AVR limiters or AVR protection for over-excitation, underexcitation, Volts/Hertz, stator voltage, or field current, or 2) generator protection changes for stator voltage, loss-of-excitation, or Volts/Hertz protection.”For only 30 days of differences (90 to 120), VSLs expand from Lower to Severe. Considering the justifiable allowance for 20% of the fleet to go 5 years without demonstrated coordination, the logic for the acceleration of severity over such a short time duration is not understood.
Response: Thank you for your comment. In response to comments regarding coordination between the loss of field protection and the SSSL in Attachment 1, the loss of field trip curve does coordinate with the SSSL. The Zone 2 and Zone 1 loss of excitation functions are providing backup protection to the primary loss of field trip. With regard to your suggestion of defining specific methods for evaluating coordination, the SDT intends the standard to be technology neutral and cannot define coordination methodologies for all current and future generating technologies. The SDT has revised the wording in R1 to clarify that protection should protect the equipment and may allow capabilities to be exceeded when appropriate. The verification time interval has been set to coordinate with MOD-025-2. Once an initial coordination evaluation has been completed, subsequent verification should not be a hardship. In response to your comment, the SDT has revised language used to trigger an evaluation. The VSL levels are set in accordance with NERC guidelines, and are appropriate for reliability concerns associated with equipment changes.		
Manitoba Hydro	Yes	-The standard should take into account generating units whose capacity is determined based

Organization	Yes or No	Question 9 Comment
		upon the run of the river where it may be difficult to test at design capacity. We suggest that an engineering methodology/calculation be acceptable for these units
Response: Thank you for your comment. The SDT believes the capability of the equipment does not change, even though equipment output may be restricted due to factors, such as run of the river. This standard does not require testing.		
Duke Energy	Yes	1) In several places in the posting documents there is a discrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 2) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 3) Section 5.2.5 is missing from effective date in the draft standard. 4) R1.1.1.1 seems to infer that the 40 relays should be set inside the Capability curves and the SSSL. The 40 relay should be set inside the SSSL but may be outside the capability curves as it is intended to prevent a pole slip. AVR protective functions may be set to protect the capability curves.
Response: Thank you for your comment. Regarding comments (1), (2), noted discrepancies have been corrected. (4) The SDT has revised the wording in R1 to clarify that protection should protect the equipment and may allow capabilities to be exceeded when appropriate.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	Yes	1. The standard introduces a local definition: “in-service”, that is subject to interpretation. Does “in-service” mean:- Installed but may or may not be put to service (e.g. mothballed)?- Installed and can be put to service at any time?- Installed and on-line?Generators/synchronous condensers will have a reliability impact only when they are connected to the grid (put on-line). However, the timing of these facilities to be put on-line is at the discretion of the GOs and perhaps under some conditions specified by other entities such as the TOP or RC. It is thus conceivable that installed facilities can be put on-line at any time. To ensure proper reliability performance, we suggest to change “in-service” to “installed” to make sure the facilities meet the standard requirements if and when they are put on-line. 2. R1.2: The wording: “verify the existence of the coordination” does not drive home the intent of ensuring the settings are coordinated and reviewed once every 5 years or as changes occur. We suggest to change R1.2 to read: “shall review and revise as necessary the coordinated settings identified in

Organization	Yes or No	Question 9 Comment
		Requirement R1 at least once every five years or within....”
Response: Thank you for your comment. Footnote 1 defines “in service” as functions that are installed and activated. Many relays have multiple protection functions that would be “installed,” but not necessarily activated. Installed protection functions that are not active do not need to be evaluated for determining proper coordination. The SDT believes standard language for verifying the existence of coordination is adequate.		
Gainesville Regional Utilities	No	
Ameren	Yes	(1) Standard needs to be more specific and clear on what evidence is need for 1.1.2. (2) Violation Severity Levels seem arbitrary and need to be reviewed, considering the standard is giving four years to be 100% complete. The system is presently operating with few if any miss-coordination on these protection systems. (3) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (4) R1.2 states there must be verification of coordination within 90 calendar days following "...identification or implementation..." of systems or changes. There is typically an enormous difference between the "identification" and the "implementation" of these systems. Would the SDT please clarify what is expected? (5) Sister Unit exemptions should be allowed for plants with multiple identical units that have identical equipment and control systems. (6) This Standard should only apply to generators with a nameplate rating of > 75 MVA and a connection to the interconnected transmission grid > 100 kV. (7) The use of "Stead state stability limit" in bullet #4 in R1 and the use of the phrase "...system steady state operating conditions." in R1.1.1, seem to conflict. Is the term in R1 intended to represent system conditions AFTER an N-1 contingency, or during N-0 conditions?
Response: Thank you for your comment. (1) The measure supports evidence needed to demonstrate compliance (2) The VSL’s are set in accordance with NERC guidelines. (3) The applicability section was revised. The phrase, “point of Interconnection” has been deleted. (4) SDT intent regard “implementation or identification of changes” is to allow the clock to start when the changes that may occur to equipment capabilities is actually identified (recognizing this awareness may not have been immediately apparent). It is expected changes implemented by the equipment owner are “identified” at the time of implementation. (5) Regarding “sister units,” there is minimal burden with verification that the in-service settings are identical (and by extension coordination). (6) The applicability section of the standard is based on the Registry criteria, and the SDT does not have sufficient technical justification to deviate		

Organization	Yes or No	Question 9 Comment
from this criteria. **(7) The standard allows evaluation of N-0 conditions. The equipment owner has discretion to perform evaluation of other conditions.**		
Indeck Energy Services		
Oncor Electric Delivery Company LLC	No	
Indiana Municipal Power Agency	Yes	IMPA does not understand the need to perform the coordination type of study every five years. It should be performed initially and only if something changes that would require a new coordination study. IMPA could see the need to verify the settings on the voltage regulating equipment, etc. just as you would with relay testing but why go through a complete study every 5 years. IMPA recommends performing the coordination study initially as per the timetable listed in the effective dates (section 5) and then again prior to the implementation of systems, equipment, setting changes, etc.IMPA recommends not using the words “verify the existence” in requirement 1.2. This wording is very vague in the sense that it may require just a review of the document to ensure no changes or does it mean that another coordination study needs to be performed. IMPA recommends using the wording “shall review the coordination identified in Requirement R1 at least once every five years or perform the coordination identified in Requirement R1 within 90 calendar days… “ if this is the intent of the SDT.
Response: Thank you for your comment. The intent of the five-year verification interval is to verify that settings have not changed. In addition, changes to the transmission system can affect the SSSL. The SDT believes the words “… verify the existence of coordination…” ensures the settings used to evaluate coordination match the in-service settings.		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Draft MOD-026-1 was posted for a 45 day comment period from February 17 – April 2, 2009.
6. Draft 2 MOD-026-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This second posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop third version draft standard.	August 2011– February 2012
2. Post response to comments and third version draft revision of standard for 30 day comment and successive ballot period.	February – March 2012
3. Develop responses to successive ballot comments.	April – May 2012
4. Post response to comments.	June 2012
5. Conduct recirculation ballot.	June2012
7. BOT adoption.	July 2012
8. File with regulatory authorities.	September 2012

A. Introduction

1. Title: Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions

2. Number: MOD-026-1

3. Purpose: To verify that the generator excitation control system and plant volt/var control[1] function model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system and plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. Applicability:

4.1. Functional Entities:

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities:

For the purpose of this standard, the following Facilities are considered, "applicable units[2]."

Units or plants with an average capacity factor[3] greater than 5 percent over the most recent three calendar years, beginning on January 1 and ending on December 31, that meet the following:

4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system.

4.2.1.2 For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating):

- Each individual generating unit greater than 20 MVA (gross nameplate rating); and

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[1] Excitation control system and plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.
b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

[2] Applicable generating units do not include startup or standby units not normally connected to the grid.

[3] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

- Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.2 Generating units connected to the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the bulk power system.

4.2.2.2 For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):

- Each individual generating unit greater than 20 MVA (gross nameplate rating); and
- Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.3 Generating units connected to the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the bulk power system.

4.2.3.2 For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):

- Each individual generating unit greater than 20 MVA (gross nameplate rating); and
- Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.4 For all Interconnections:

- Any registered technically justified[4] unit requested by the Planning Coordinator.

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter, four years following applicable regulatory approval.

[4] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

5.1.2 Each Generator Owner shall ensure at least 30 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval.

5.1.3 Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval:

5.1.4 Each Generator Owner shall ensure 100 percent of its applicable units are compliant with Requirement R2 by the first day of the first calendar quarter, ten years following applicable regulatory approval:

5.2. In those jurisdictions where no regulatory approval is required:

5.2.1 Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter, four years following Board of Trustees adoption.

5.2.2 Each Generator Owner shall ensure at least 30 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.

5.2.3 Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.

5.2.4 Each Generator Owner shall ensure 100 percent of its applicable units are compliant with Requirement R2 by the first day of the first calendar quarter, ten years following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Planner shall provide the following instructions and model data to its requesting Generator Owner within 90 calendar days of receiving a request for those instructions or model data: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*:

- Instructions on how to obtain the list of excitation control system and plant volt/var control function models acceptable to the Transmission Planner for use in dynamic simulation.
- Instructions on how to obtain the Transmission Planner's software manufacturer's dynamic excitation control system and plant volt/var control function model library block diagrams and/or data sheets.
- Model data for any of the Generator Owner's existing unit or plant specific excitation control system and plant volt/var control function contained in the

Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide, for each of its applicable units, a verified generator excitation control system and plant volt/var control function model including documentation and data as specified in Parts 2.1 and 2.2 to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1, to ensure modeling data is accurate for use in simulation software. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Perform verifications using one or more models acceptable to the Transmission Planner that include(s) the following information:

2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion at the applicable unit's point of interconnection from either a staged test or a measured system disturbance.

2.1.2. Manufacturer, model number (if available), and type of excitation control system and plant volt/var control function installed (such as static, AC brushless, DC rotating, volt/var function).

2.1.3. Model structure and data (such as reactance, time constants, saturation factors, rotational inertia, or equivalent data) for the generator (or plant equivalent).

2.1.4. Model structure and data for the excitation control system, for the plant volt/var function, and for the closed loop voltage regulator if the closed loop voltage regulator is installed.

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used.

2.1.6. Model structure and data for power system stabilizer, if so equipped.

2.2. For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items. The written response shall contain either the technical basis for maintaining the current model, or the model changes, or a plan to perform model verification[5] (in accordance with Requirement R2) *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*:

- Written notification from its Transmission Planner (in accordance with Requirement R6) that the excitation control system and plant volt/var control function model is not "usable," or

[5] If verification is performed, the 10 year period as outlined in Attachment 1 is reset.

- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system and plant volt/var control function model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the predicted excitation control system and plant volt/var control function model response did not match the recorded response to a transmission system event.

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[5] (in accordance with Requirement R2) to its Transmission Planner within 180 calendar days of making changes to the excitation control system and plant volt/var control function that alter the equipment response[6] characteristic. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant not included in the Applicability that includes one of the following *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*:

- Details of plans to verify the model (in accordance with Requirement R2)
- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on a walk down of the equipment.

R6. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system and plant volt/var control function model information whether the model is useable (meets the criteria specified in Parts 6.1 through 6.3), or is not useable; and shall include a technical description if the model is not useable. . *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

6.1. The excitation control system and plant volt/var control function model initializes to compute modeling data without error.

6.2. A no-disturbance simulation results in negligible transients.

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

C. Measures

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[6] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change.

M1. Evidence for Requirement R1 must include the transmitted instructions or data and dated evidence of transmission of requested instructions and data, such as dated electronic mail messages, dated postal receipts, dated confirmation of facsimile transmission.

M2. Evidence for Requirement R2 must include, for each of the Generator Owner's applicable Facilities, the verification report showing that the generator excitation control system and plant volt/var control function model was verified and dated evidence of transmission, such as a dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmission as specified in Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal, such as a dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmission.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's Facilities for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal, such as dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmittal.

M5. Evidence for Requirement R5 must include, for each request received as specified in Requirement R5, the dated written response provided and dated evidence of transmittal, such as dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmittal.

M6. Evidence of Requirement R6 must include, for each model received, the dated response containing the information required in Parts 6.1 through 6.3 and dated evidence of transmittal, such as dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmittal.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance

Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest and previous excitation control system and plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but no more than 120 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but no more than 150 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but no more than 180 calendar days of receiving a request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 181 calendar days of receiving a request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the timeframe specified in MOD-026 Attachment 1 but no more than 30 calendar days late; OR The Generator Owner provided the Transmission Planner verified models that omitted one of the six Parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 30 calendar days but no more than 60 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted two of the six Parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 60 calendar days but no more than 90 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the six Parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.	The Generator Owner provided its verified generator excitation control system and plant volt/var control function model more than 90 calendar days late or failed to provide the verified model(s) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Subpart 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the six Parts identified in

				Requirement R2, Subparts 2.1.1 through 2.1.6.
R3	The Generator Owner provided a written response more than 90 calendar days but no more than 120 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 120 calendar days but no more than 150 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 150 calendar days but no more than 180 calendar days of receiving written notice. (R3)	The Generator Owner failed to provide a written response within 181 calendar days of receiving written notice (R3). OR The Generator Owner's written response was provided within 181 calendar days of receiving written notice however, the Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but no more than 210 calendar days of making changes to the excitation control system and plant volt/var control function that altered the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but no more than 240 calendar days of making changes to the excitation control system and plant volt/var control function that altered the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but no more than 270 calendar days of making changes to the excitation control system and plant volt/var control function that altered the equipment response characteristic. (R4)	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 271 calendar days of making changes to the excitation control system and plant volt/var control function that altered the equipment response characteristic (R4).
R5	The Generator Owner provided a written response more than 90 calendar days but no more than 120 calendar days to the Planning Coordinator following receipt of a technically justified request to	The Generator Owner provided a written response more than 120 calendar days but no more than 150 calendar days to the Planning Coordinator following receipt of a technically justified request to	The Generator Owner provided a written response more than 150 calendar days but no more than 180 calendar days to the Planning Coordinator following receipt of a technically justified request to	The Generator Owner failed to provide a written response to the Planning Coordinator following receipt of a technically justified request to perform a model review of

	perform a model review of a unit/plant. (R5)	perform a model review of a unit/plant. (R5)	perform a model review of a unit/plant. (R5) OR The Generator Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the written response failed to include Requirement R5, Subpart 5.2 or Part 5.3.	a unit/plant (R5). OR The Generator Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the written response failed to include Requirement R5, Subparts 5.2 and 5.3.
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R6)	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 120 calendar days but less than 150 calendar days of receiving the verified model information. (R6) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for one of the specified model criteria listed in Requirement R6, Subparts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 150 calendar days but less than 180 calendar days of receiving the verified model information. (R6) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for two of the specified model criteria listed in Requirement R6, Subparts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 181 calendar days of receiving the verified model information (R6). OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for all specified model criteria listed in Requirement R6, Subparts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, “Model Validation for Wind Turbine Generator Models”, IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, “Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, “Dynamic Modeling of GE Wind Plants for Stability Simulations,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, “Description and Technical Specifications for Generic WTG Models – A Status Report,” Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ
9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010

10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, “Modeling of GE Wind Turbine-Generators for Grid Studies,” version 4.5, April 16, 2010, Available from GE Energy

11. R.J. Piwko, N.W. Miller, J.M. MacDowell, “Field Testing & Model Validation of Wind Plants,” in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008

12. N. Miller, K. Clark, J. MacDowell and W. Barton, “Experience with Field and Factory Testing for Model Validation of GE Wind Plants,” in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belguim, March/April 2008

13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307

14. W.W.Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992

15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006

16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, “Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations,” Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003

17. P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-026 Attachment 1

Excitation Control System and Plant Volt/Var Function Model Verification Periodicity

Periodicity Determination Supporting Criteria
Criteria 1: Establishing the Initial Ten Year Unit Verification Period Start Date: **For each applicable unit, set the initial start date for compliance with Requirement R2 to the 30 percent, 50 percent, or 100 percent Standard Implementation Effective Dates established for compliance in accordance with the ten calendar year transition period and in accordance with the following rules:** • **30 percent of the applicable units in the generation fleet unit MVA is compliant within the first 4 years.** • **50 percent of the applicable units in the generation fleet unit MVA is compliant within the first 6 years.** • **100 percent of the applicable units in the generation fleet unit MVA is compliant within the first 10 years.** **Criteria 2: Establishing the Recurring Ten Year Unit Verification Period Start Date:** **The start date is the actual data collection date for the most recently performed applicable unit verification.** **Criteria 3: For the purpose of calculating the initial ten year unit verification period 30 percent, 50 percent, or 100 percent threshold for generation fleet compliance, equivalent unit MVA is included.** **Consideration for Early Compliance** **Existing excitation control system and plant volt/var control function model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:** • **The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification** • **The Generator Owner has an existing verified model that is compliant with the requirements of this standard.**

Event Triggering Verification	Verification Periodicity	Comments
Establishing the initial verification period (Criteria 1) for an applicable unit (Requirement R2)	Record and collect excitation control system and plant volt/var control response validation data on or before the initial start date per Criteria 1	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded. Criteria 3 applies when calculating generation fleet compliance during the 10-year transition period
Subsequent verification for an existing applicable unit (Requirement R2)	Record and collect excitation control system and plant volt/var control function response validation data on or before the ten year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control function response used for the current validation.	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected.
Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system and plant volt/var control function equipment installed with settings final (Requirement R2)	Record and collect excitation control system and plant volt/var control function response validation data no more than 356 days from the commissioning date	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
Existing applicable unit that is equivalent to another operating unit(s) at the same physical location. AND Each equivalent unit has the same MVA nameplate rating. AND	Verify a different equivalent unit during each ten year verification period. .	Document circumstance with a written statement and include with the verified model and documentation and data provided to the Transmission Provider for the verified equivalent unit.

Event Triggering Verification	Verification Periodicity	Comments
The nameplate rating is ≤ 350 MVA. AND Each equivalent unit has identical applicable components and settings. AND The model for one of these equivalent units has been verified. (Requirement R2)		Criteria 3 applies when calculating generation fleet compliance during the 10-year transition period.
Existing unit was subjected to an activity that resulted in an alteration of the response of the excitation control system and plant volt/var control function model and the altered unit settings are final AND The Generator Owner has submitted a verification plan. (Requirement R4)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
The Generator Owner receives written comments including dated electronic or hard copy evidence indicating that the recorded excitation control system and plant volt/var response to a transmission system event did not did not match the predicted excitation control system model response. AND The Generator Owner has submitted a verification plan. (Requirement R3)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
The Generator Owner receives written comments detailing technical concerns with the Generator Owner's excitation control system and plant volt/var control function model verification documentation.	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that

Event Triggering Verification	Verification Periodicity	Comments
AND The Generator Owner has submitted a verification plan (Requirement R3)	submitted verification plan.	the recorded response was collected.
The excitation control system and volt/var control model are identified as unusable by the Transmission Planner. AND The Generator Owner has submitted a verification plan. (Requirement R3)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
Planning Coordinator requests a review of the excitation control system and plant volt/var control function model for a unit or plant that is not an applicable unit. AND The Generator Owner has submitted a verification plan. (Requirement R5)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
New or existing applicable unit does not include active closed loop function.	Not required until unit has an installed control system	Document circumstance with a written statement Perform verification per the periodicity specified in Row 3 for a “New Generating Unit” (or new equipment) once an active closed loop function is established.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps ~~-~~Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Draft MOD-026-1 was posted for a 45 day comment period from February 17 – April 2, 2009.
6. Draft 2 MOD-026-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.

Proposed Action Plan and Description of Current Draft:

This is the ~~first~~third draft of the ~~this~~ standard ~~including~~and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This second posting is for a ~~45~~30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. ~~Post first~~Develop responses to comments and develop third version draft ~~revision of~~ standard.	~~April-May~~August 2011– February 2012
2. Post response to comments and third version draft revision of standard for 30 day comment and successive ballot period.	~~July – August 2011~~February – March 2012
3. ~~Post response~~Develop responses to successive ballot comments ~~and request authorization to ballot the revised standard~~.	~~September - October 2011~~April – May 2012
~~4. Conduct initial ballot.~~	~~November 2011~~
~~5~~4. Post response to comments.	~~December 2011~~June 2012
~~6~~5. Conduct recirculation ballot.	~~January 2012~~June2012
7. BOT adoption.	~~February~~July 2012
8. File with regulatory authorities.	~~March~~September 2012

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control -Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the generator excitation control system and plant volt/var control[1] [1] function model (including the power system stabilizer model and the impedance compensator model),) and the model parameters used in dynamic simulations accurately represent the generator excitation control ~~systems~~system and plant volt/var control[2] function behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

   4.1. Functional ~~entities~~Entities:

   4.1.1 Generator Owner

   4.1.2 Transmission Planner

   4.2. Facilities:

   For the purpose of this standard, the following Facilities are considered, "applicable units.~~"~~ [3]."

   Units or plants with an average capacity factor[4] greater than 5~~%~~ percent over the ~~last~~most recent three calendar years, beginning on January 1 and ending on December 31, that meet the following:

   4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

   ~~•~~**4.2.1.1** ~~Each~~Individual generating unit ~~with a~~ greater than 100 MVA (gross nameplate rating ~~greater than 100 MVA,~~) directly connected

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[1] Excitation control system and plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.

b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

~~[2] Excitation control system or plant volt/var control system:~~

~~a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.~~

~~b. For an aggregate generation plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.~~

[3] Applicable generating units do not include startup or standby units not normally connected to the grid.

[4] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

~~at~~to the ~~point of interconnection[5] at greater than or equal to 100 kV~~bulk power system.

- **4.2.1.2** For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with ~~a~~ total generation greater than 100 MVA (gross aggregate ~~nameplate~~ rating ~~greater than to 100 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:~~):
  - Each individual generating unit ~~with a~~ greater than 20 MVA (gross nameplate rating ~~greater than 20 MVA;~~); and
  - ~~The remainder of the plant as an aggregate.~~
  - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.2 Generating units connected to the Western Interconnection with the following characteristics:

- **4.2.2.1** ~~Each~~Individual generating unit ~~with a~~ greater than 75 MVA (gross nameplate rating ~~greater than 75 MVA,~~) directly connected ~~at~~to the ~~point of interconnection[3] at greater than or equal to 100 kV~~bulk power system.
- **4.2.2.2** For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with ~~a~~ total generation greater than 75 MVA (gross aggregate ~~nameplate~~ rating ~~greater than 75 MVA, connected at the same point of interconnection with at greater than or equal to 100 kV:~~):
  - Each individual generating unit ~~with a gross nameplate~~ greater than 20 MVA~~;~~ (gross nameplate rating); and
  - ~~The remainder of the plant as an aggregate.~~
  - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.3 Generating units connected to the ERCOT Interconnection with the following characteristics:

- **4.2.3.1** ~~Each~~Individual generating unit ~~with a~~ greater than 50 MVA (gross nameplate rating ~~of greater than 50 MVA,~~) directly connected ~~at~~to the ~~point of interconnection[3] with rating greater than or equal to 100 kV~~bulk power system.
- **4.2.3.2** For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with ~~a~~

~~[5] The common transmission bus voltage level at which the generator step-up transformer is connected.~~

total generation greater than 75 MVA (gross aggregate ~~nameplate~~ rating ~~of greater than 75 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:~~):

- Each individual generating unit ~~with a gross nameplate~~ greater than 20 MVA~~;~~ (gross nameplate rating); and
- ~~The remainder of the plant as an aggregate.~~
- Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.4 For all ~~interconnections:~~Interconnections:

- Any registered technically justified[6] unit requested by the Planning Coordinator.

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 ~~By~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter, four years following applicable regulatory approval~~:~~.

~~•~~**5.1.2** Each Generator Owner shall ensure at least 30~~%~~ percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval.

- ~~•~~ Each ~~responsible entity~~Generator Owner shall ensure ~~compliance~~at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with ~~Requirements R1, and R3 through R6.~~

~~**5.1.2**~~**5.1.3** ~~By~~Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval:

- ~~•~~ Each Generator Owner shall ensure ~~at least 50%~~100 percent of its applicable units ~~per Interconnection on an MVA basis~~ are compliant with Requirement R2~~.~~

~~**5.1.3**~~**5.1.4** ~~By~~ by the first day of the first calendar quarter, ten years following applicable regulatory approval:

- ~~Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2.~~

5.2. In those jurisdictions where no regulatory approval is required:

[6] ~~A technical~~Technical justification ~~for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence~~is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

5.2.1 ~~By~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter, four years following Board of Trustees adoption~~:~~.

5.2.2 Each Generator Owner shall ensure at least 30~~%~~ percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.

- ~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6.~~

~~**5.2.2** By the first day of the first calendar quarter, six years following Board of Trustees adoption:~~

5.2.3 Each Generator Owner shall ensure at least 50~~%~~ percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.

~~**5.2.3** By the first day of the first calendar quarter, ten years following Board of Trustees adoption:~~

5.2.4 Each Generator Owner shall ensure 100~~%~~ percent of its applicable units are compliant with Requirement R2 by the first day of the first calendar quarter, ten years following Board of Trustees adoption.

~~**6. Consideration for Early Compliance**~~

~~**6.1.** Existing excitation control system and plant volt/var control[1] model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if:~~

- ~~The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification (provided the model verification addresses the same unit criteria and the same information as required by this standard), or~~
- ~~The Generator Owner has an existing verified model that is compliant with the requirements of this standard.~~

B. Requirements

R1. Each Transmission Planner shall provide the following instructions and model data to its requesting Generator Owner within ~~30~~90 calendar days of receiving ~~the~~a request ~~from its Generator Owner~~ for those instructions ~~and~~or model data: *[Violation Risk Factor: Lower] [Time Horizon: ~~Long-term~~Operations Planning~~]~~]:*

- Instructions on how to obtain the list of ~~acceptable~~ excitation control system and plant volt/var control[1] function ~~model~~models acceptable to the Transmission Planner for use in dynamic simulation.

- Instructions on how to obtain the Transmission Planner's software manufacturer's dynamic excitation control system and plant volt/var control~~[1]~~ function~~ system~~ model library block diagrams and/or data sheets.
- ~~Any~~Model data for any of the Generator Owner's existing unit or plant specific excitation control system and plant volt/var control~~[1]~~~~ model data~~ function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide, for each of its applicable units, a verified generator excitation control system and plant volt/var control~~[1]~~ function model ~~(for each of its applicable Facilities)~~including documentation and data as specified in Parts 2.1 and 2.2 to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1, to ensure modeling data is accurate for use in simulation software~~ subject to the following:~~. *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: Long-term Planning]*

2.1. ~~Each Generator Owner shall perform its~~Perform verifications ~~with~~using one or more models acceptable to ~~its~~the Transmission Planner that ~~collectively~~ include(s) the following information:

2.1.1. Documentation demonstrating the ~~unit or plant's~~applicable unit's model response matches the recorded response for a voltage excursion at the ~~generator or plant~~applicable unit's point of interconnection from either a staged test or a measured system disturbance.

2.1.2. Manufacturer, model number (if available), and type of excitation control system and plant volt/var control~~[1]~~~~ system~~ function installed (such as static, ~~ac~~AC brushless, ~~dc~~DC rotating, volt/var ~~system~~function).

2.1.3. ~~Generator (or plant equivalent) model~~Model structure and data (such as reactance, time constants, saturation factors, rotational inertia, or equivalent data) for the generator (or plant equivalent).

2.1.4. ~~Excitation~~Model structure and data for the excitation control system~~ and~~, for the plant volt/var ~~system model structure~~function, and ~~data~~ for the closed loop voltage regulator if the closed loop voltage regulator is installed.

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used.

2.1.6. Model structure and data for power system stabilizer, if so equipped.

2.2. For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6

R3. Each Generator Owner shall provide a written response ~~that contains~~to its Transmission Planner within 90 calendar days of receiving one of the following items. The written response shall contain either the technical basis for maintaining the current model, ~~a list of future~~or the model changes, or a plan to perform model verification[7] ~~to its Transmission Planner within 90 calendar days of receiving notice of one of the following:~~(in accordance with Requirement R2) *[Violation Risk Factor: Lower] [Time Horizon: ~~Long-term~~Operations Planning~~]~~]:*

- Written notification~~, including a technical description~~ from its Transmission Planner ~~of why~~(in accordance with Requirement R6) that the excitation control system and plant volt/var control~~[1]~~ ~~system~~ function model is not "usable~~" as identified in Requirement R6, Parts 6.1 through 6.3 criteria,~~," or

- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system and plant volt/var control~~[1]~~ ~~system~~ function model, or

- Written comments and supporting evidence from its Transmission Planner indicating that the predicted excitation control system and plant volt/var control~~[1]~~ function model response did not match the recorded response to a transmission system event.

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[7] (in accordance with Requirement R2) to its Transmission Planner within 180 calendar days of making changes to the excitation control system and plant volt/var control~~[1]~~ ~~system~~ function that alter the equipment response[8] characteristic. *[Violation Risk Factor: Lower] [Time Horizon: ~~Long-term~~Operations Planning]*

R5. Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of ~~a~~any unit/plant not included in the Applicability that ~~meets~~includes one of the following~~:~~ *[Violation Risk Factor: Lower] [Time Horizon: ~~Long-term~~Operations Planning~~]~~]:*

~~5.1. Submit within 90 calendar day's receipt~~Details of ~~the technically justified~~[4] ~~request.~~

- ~~Either indicate~~ plans to verify the model ~~or identify~~ (in accordance with Requirement R2)

~~5.2.~~ Corrected model data including the source of revised model data such as~~:~~

- ~~Discovery~~ discovery of manufacturer test values to replace generic model data~~.~~

- ~~Updating~~ or updating of data parameters based on a walk down of the equipment.

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[7] If verification is performed, the 10 year period as outlined in Attachment 1 is reset.

[8] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change.

~~5.3.~~ ~~Include corrected~~ Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system and plant volt/var control[1] function model ~~data.~~

R6. ~~Each Transmission Planner shall determine if the verified generator excitation control system and plant volt/control[1] model received~~ information whether the model is useable (meets the criteria ~~identified in Requirement R6~~specified in Parts 6.1 through 6.3 ~~and provide a written response to the Generator Owner indicating whether the model is useable~~), or is not useable; ~~including~~and shall include a technical description if the model is not useable. ~~This written response shall be submitted within 90 calendar days of receiving the excitation control system and plant volt/var control[1] verified model information~~. *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: ~~Long-term~~Operations Planning]*

6.1. The excitation control system and plant volt/var control[1] function model ~~can initialize~~initializes to compute modeling data without error.

6.2. A no-disturbance simulation results in negligible transients.

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control[1] ~~system~~ function model exhibiting positive damping.

C. Measures

M1. ~~Each Transmission Planner shall have evidence to show that it provided~~ Evidence for Requirement R1 must include the transmitted instructions or data and dated evidence of transmission of requested instructions and data ~~(~~, such as dated electronic mail messages ~~or mail~~, dated postal receipts ~~) within 30 calendar days of receiving a request as specified in Requirement R1~~, dated confirmation of facsimile transmission.

~~M2.~~ ~~Each Generator Owner shall have evidence (such as a dated electronic mail messages or mail receipts) including~~Evidence for Requirement R2 must include, for each of the Generator Owner's applicable Facilities, the verification report ~~to show~~showing that ~~it provided~~ the ~~verified~~ generator excitation control system ~~or~~and plant volt/var control[1] function model ~~as specified in Requirement R2.~~

~~M3.~~**M2.** ~~Each Generator Owner shall have~~ was verified and dated evidence ~~to show that it provided a written response (~~of transmission, such as a dated ~~copy of the response, or dated~~ electronic mail messages ~~or mail~~, dated postal receipts ~~) containing identified information and submitted within 90 calendar days~~, or dated confirmation of ~~receiving any written notification~~facsimile transmission as specified in Requirement ~~R3.~~R2.

M3. ~~Each~~ Evidence for Requirement R3 must include the Generator ~~Owner shall have evidence to show that it provided a~~ Owner's dated written response ~~(~~containing the information identified in Requirement R3 and dated evidence of transmittal, such as a dated ~~copy of the request, or dated~~ electronic mail messages ~~or mail~~ , dated postal receipts ~~) submitted within 180 calendar days~~, or dated confirmation of ~~making~~facsimile transmission.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's Facilities for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal, such as dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmittal.

M5. ~~Each Generator Owner shall have evidence to show that it provided a written response (~~Evidence for Requirement R5 must include, for each request received as specified in Requirement R5, the dated written response provided and dated evidence of transmittal, such as dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmittal.

~~**M5.**~~ Evidence of Requirement R6 must include, for each model received, the dated response containing the information required in Parts 6.1 through 6.3 and dated evidence of transmittal, such as dated electronic mail messages~~ or mail receipts) and submitted within 90 calendar days of receiving the request as specified in Requirement R5.~~

M6. ~~Each Transmission Planner shall have evidence to show that it provided a written response (such as dated electronic mail messages or mail~~, dated postal receipts~~) within 90 calendar days of receiving the model as specified in Requirement R6~~, or dated confirmation of facsimile transmittal.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest and previous excitation control system and plant volt/var control~~[1] system~~ function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance ~~Audits~~Audit

Self-~~Certifications~~Certification

Spot Checking

Compliance ~~Violation Investigations~~Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but ~~less~~no more than ~~or equal to~~ 120 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but ~~less~~no more than ~~or equal to~~ 150 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but ~~less~~no more than ~~or equal to~~ 180 calendar days of receiving a request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 181 calendar days of receiving a request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the ~~periodicity~~ timeframe specified in MOD-026 Attachment 1 but ~~less~~no more than ~~or equal to~~ 30 calendar days late; OR The Generator Owner provided the Transmission Planner verified ~~model(s)~~models that omitted one of the six Parts identified in Requirement R2, ~~Parts~~Subparts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 30 calendar days but ~~less~~no more than ~~or equal to~~ 60 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified ~~model(s)~~models that omitted two of the six Parts identified in Requirement R2, ~~Parts~~Subparts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 60 calendar days but ~~less~~no more than ~~or equal to~~ 90 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified ~~model(s)~~models that omitted three of the six Parts identified in Requirement R2, ~~Parts~~Subparts 2.1.1 through 2.1.6.	The Generator Owner ~~failed to provide the~~provided its verified generator excitation control system ~~or~~and plant volt/var control function model~~(s)~~ more than 90 calendar days late or failed to provide the verified model(s) ~~no more than 90 calendar days late~~ to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, ~~Part~~Subpart 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of

				the six Parts identified in Requirement R2, ~~Parts~~Subparts 2.1.1 through 2.1.6.
R3	The Generator Owner provided a written response more than 90 calendar days but ~~less~~no more than ~~or equal to~~ 120 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 120 calendar days but ~~less~~no more than ~~or equal to~~ 150 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 150 calendar days but ~~less~~no more than ~~or equal to~~ 180 calendar days of receiving written notice. (R3)	The Generator Owner failed to provide a written response within 181 calendar days of receiving written notice ~~as specified in Requirement~~ (R3~~.~~). OR The Generator Owner's written response was provided within 181 calendar days of receiving written notice however, the Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but ~~less~~no more than ~~or equal to~~ 210 calendar days of making changes to the excitation control system ~~or~~and plant volt/var control[1] ~~system~~ function that altered the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but ~~less~~no more than ~~or equal to~~ 240 calendar days of making changes to the excitation control system ~~or~~and plant volt/var control[1] ~~system~~ function that altered the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but ~~less~~no more than ~~or equal to~~ 270 calendar days of making changes to the excitation control system ~~or~~and plant volt/var control[1] ~~system~~ function that altered the equipment response characteristic. (R4)	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 271 calendar days of making changes to the excitation control system ~~or~~and plant volt/var control[1] ~~system~~ function that altered the equipment response characteristic ~~as specified in Requirement~~ (R4~~.~~).
R5	The Generator Owner provided a written response more than 90 calendar days but ~~less~~no more than ~~or equal to~~ 120 calendar days to	The Generator Owner provided a written response more than 120 calendar days but ~~less~~no more than ~~or equal to~~ 150 calendar days to the	The Generator Owner provided a written response more than 150 calendar days but ~~less~~no more than ~~or equal to~~ 180 calendar days to the	The Generator Owner failed to provide a written response to the Planning Coordinator following receipt of a technically justified

	the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant. (R5)	Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant. (R5)	Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant. (R5) OR The Generator Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the written response failed to include Requirement R5, ~~Part~~Subpart 5.2 or Part 5.3.	request to perform a model review of a unit/plant ~~as specified in Requirement R5.~~(R5). OR The Generator Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the written response failed to include Requirement R5, ~~Parts~~Subparts 5.2 and 5.3.
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R6)	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 120 calendar days but less than 150 calendar days of receiving the verified model information. (R6) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for one of the specified model criteria listed in Requirement R6, ~~Parts~~Subparts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 150 calendar days but less than 180 calendar days of receiving the verified model information. (R6) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for two of the specified model criteria listed in Requirement R6, ~~Parts~~Subparts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 181 calendar days of receiving the verified model information ~~as specified in Requirement R6.~~(R6). OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for all specified model criteria listed in Requirement R6, ~~Parts~~Subparts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. ~~A. Ellis~~M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, ~~J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of~~ S. A. Seman, and K. Wiens, "Model Validation for Wind Turbine Generator Models", IEEE Transactions on Power ~~Generation and IEEE Working Group on Dynamic Performance of Wind Power Generation, Description and Technical Specifications for Generic WTG models – A Status Report, IEEE PES General Meeting~~System, Volume 26, Issue 3, August 2011~~, Detroit, MI, July 24-28~~
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, "Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies," IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, "Dynamic Modeling of GE Wind Plants for Stability Simulations," IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, "Description and Technical Specifications for Generic WTG

Models – A Status Report," Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ

9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, "Modeling of GE Wind Turbine-Generators for Grid Studies," version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, "Field Testing & Model Validation of Wind Plants," in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, "Experience with Field and Factory Testing for Model Validation of GE Wind Plants," in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belguim, March/April 2008
13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES General Meeting 2007, paper 07GM1307
14. W.W.Price and J. J. Sanchez-Gasca, "Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies," in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, "On the Integration of Wind Power Plants in Large Power Systems," Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, "Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations," Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003

17. ~~OD~~P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-026 Attachment 1

Excitation Control System ~~or~~and Plant Volt/~~VAr~~Var Function Model Verification Periodicity

~~Note that local grid codes may specify shorter time frames.~~

~~Facility~~	~~Condition~~	Periodicity Determination Supporting Criteria

~~Existing Generating Unit~~		~~During the eleven calendar year (January – December) transition period and **no exceptions** apply.~~ ~~**OR**~~ ~~During the ten calendar year (January – December) period and **no exceptions** apply.~~	~~A recorded response for a voltage excursion shall be collected during a~~ **Criteria 1: Establishing the Initial Ten Year Unit Verification Period Start Date:** **For each applicable unit, set the initial start date for compliance with Requirement R2 to the 30 percent, 50 percent, or 100 percent Standard Implementation Effective Dates established for compliance in accordance with the ten calendar year** ~~(January – December)~~ **transition period and in accordance with the following rules:** • **30 percent of the applicable units in the generation fleet unit MVA is compliant within the first 4 years.** • **50 percent of the applicable units in the generation fleet unit MVA is compliant within the first 6 years.** • **100 percent of the applicable units in the generation fleet unit MVA is compliant within the first 10 years.** **Criteria 2: Establishing the Recurring Ten Year Unit Verification Period Start Date:** **The start date is the actual data collection date for the most recently performed applicable unit verification.** **Criteria 3: For the purpose of calculating the initial ten year unit verification period 30 percent, 50 percent, or 100 percent threshold for generation fleet compliance, equivalent unit MVA is included.** **Consideration for Early Compliance** **Existing excitation control system and plant volt/var control function model verification is sufficient for demonstrating compliance for a ten year period from the** ~~effective date~~ **actual verification date if either of the following applies:** • **The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification** • **The Generator Owner has an existing verified model that is compliant with the requirements of this standard** ~~with the verified model and documentation transmitted to the Transmission Planner no more than 365 days from the date that the recorded response was collected.~~**.**

~~Existing Generating Unit~~	~~During the eleven calendar year (January - December) transition period.~~ ~~**OR**~~ ~~During the ten calendar year (January - December) period.~~ ~~**AND**~~ ~~T**he following exception** applies:~~ ~~1) Multiple units have the same MVA nameplate rating that are ≤ 350 MVA **AND**~~ ~~2) The same multiple units have identical applicable components and settings **AND**~~ ~~3) The same multiple units are sited at the same physical location **AND**~~ ~~4) The model for one of these equivalent units has been verified.~~	~~Not Required (however, perform verification on a different unit each ten calendar year cycle).~~
~~Existing Generating Unit~~	~~Installation of new excitation control system equipment.~~	~~A recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 days from the new equipment commissioning date..~~
~~Existing Generating Unit~~	~~Subjected to an activity resulting in an alteration of the response of the~~	~~A recorded response for a voltage excursion shall be collected within 365~~

	~~excitation control system.~~	~~days of settings or software changes with the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~Existing Generating Unit~~	~~Receive written comments including dated electronic or hard copy evidence indicating that the recorded excitation control system response to a Transmission System event did not match the predicted excitation control system model response.~~	~~A recorded response for a voltage excursion shall be collected within 365 days of a written response by the Generator Owner committing to perform model verification with the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~Existing Generating Unit~~	~~A model verification plan submitted as a result of a review requested by the Planning Coordinator for an existing Generating Unit.~~	~~A recorded response for a voltage excursion shall be collected within 365 days of the submission of a plan to perform model verification as a result of a request for a review from the Planning Coordinator with the verified model and documentation specified in transmitted to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~New or Existing Generator Unit~~	~~Excitation control system model identified as unusable by the Transmission Planner.~~ **~~OR~~** ~~Receive written comments detailing technical concerns with the Generator Owner's excitation control system model verification~~	~~A recorded response for a voltage excursion shall be collected within 365 days of a written response by the Generator Owner committing to perform model verification with the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days from the date that the~~

	~~documentation.~~	~~recorded response was collected.~~
~~New Generating Unit~~	~~New unit installed~~	~~A recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit commercial operating date.~~

Event Triggering Verification	Verification Periodicity	Comments
Establishing the initial verification period (Criteria 1) for an applicable unit (Requirement R2)	Record and collect excitation control system and plant volt/var control response validation data on or before the initial start date per Criteria 1	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded. Criteria 3 applies when calculating generation fleet compliance during the 10-year transition period
Subsequent verification for an existing applicable unit (Requirement R2)	Record and collect excitation control system and plant volt/var control function response validation data on or before the ten year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control function response used for the current validation.	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected.
Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system and plant volt/var control function	Record and collect excitation control system and plant volt/var control	Transmit the verified model and documentation and data to the

Event Triggering Verification	Verification Periodicity	Comments
equipment installed with settings final (Requirement R2)	function response validation data no more than 356 days from the commissioning date	Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
Existing applicable unit that is equivalent to another operating unit(s) at the same physical location. AND Each equivalent unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each equivalent unit has identical applicable components and settings. AND The model for one of these equivalent units has been verified. (Requirement R2)	Verify a different equivalent unit during each ten year verification period. .	Document circumstance with a written statement and include with the verified model and documentation and data provided to the Transmission Provider for the verified equivalent unit. Criteria 3 applies when calculating generation fleet compliance during the 10-year transition period.
Existing unit was subjected to an activity that resulted in an alteration of the response of the excitation control system and plant volt/var control function model and the altered unit settings are final AND The Generator Owner has submitted a verification plan. (Requirement R4)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
The Generator Owner receives written comments including dated electronic or hard copy evidence indicating that the recorded excitation control system and	Record and collect excitation control system and plant volt/var control	Transmit the verified model and documentation and data to the

Event Triggering Verification	Verification Periodicity	Comments
plant volt/var response to a transmission system event did not did not match the predicted excitation control system model response. AND The Generator Owner has submitted a verification plan. (Requirement R3)	response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
The Generator Owner receives written comments detailing technical concerns with the Generator Owner's excitation control system and plant volt/var control function model verification documentation. AND The Generator Owner has submitted a verification plan (Requirement R3)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
The excitation control system and volt/var control model are identified as unusable by the Transmission Planner. AND The Generator Owner has submitted a verification plan. (Requirement R3)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
Planning Coordinator requests a review of the excitation control system and plant volt/var control function model for a unit or plant that is not an applicable unit. AND The Generator Owner has submitted a verification plan. (Requirement R5)	Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.
New or existing applicable unit does not include active closed loop function.	Not required until unit has an installed control system	Document circumstance with a written statement

Event Triggering Verification	Verification Periodicity	Comments
		Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) once an active closed loop function is established.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Transmission Planner
Generator Owner

For the purpose of this standard, the following Facilities are considered, "applicable units[1]."

Units or plants with an average capacity factor[2] greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system.

[1] Applicable generating units do not include startup or standby units not normally connected to the grid.
[2] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

- For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating):
  - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
  - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
  - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
  - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

For all Interconnections:

- Any registered technically justified[3] unit requested by the Planning Coordinator.

[3] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter, four years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval.
- Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2 By the first day of the first calendar quarter, ten years following applicable regulatory approval.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2 By the first day of the first calendar quarter, ten years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements ten years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Retirements

None

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions

Approvals Requested

MOD-026-1 - Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of MOD-026-1:

- Transmission Planner
- Generator Owner

- Facilities

  For the purpose of this standard, the following Facilities are considered, "applicable units[1]." Units or plants with an average capacity[2] factor greater than 5% over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following:

[1] Applicable generating units do not include startup or standby units not normally connected to the grid.

[2] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date.

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant / Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

For all Interconnections:

- Any registered technically justified[3] unit requested by the Planning Coordinator.

~~Generating units connected to the Eastern or Quebec Interconnection with the following characteristics:~~

- ~~Each generating unit with a gross nameplate rating greater than or equal to 100 MVA, connected at the point of interconnection[4] with rating greater than or equal to 100 kV.~~
- ~~For each plant with a gross aggregate nameplate rating greater than or equal to 100 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV:~~
  - ~~Each unit with a gross nameplate rating greater than or equal to 20 MVA; and~~
  - ~~The remainder of the plant as an aggregate.~~

~~Generating units connected to the Western Interconnection with the following characteristics:~~

- ~~Each generating unit with a gross nameplate rating greater than or equal to 75 MVA, connected at the point of interconnection[2] with rating greater than or equal to 100 kV.~~
- ~~For each plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV:~~
  - ~~Each unit with a gross nameplate rating greater than or equal to 20 MVA; and~~
  - ~~The remainder of the plant as an aggregate.~~

~~Generating units connected to the ERCOT Interconnection with the following characteristics:~~

- ~~Each generating unit with a gross nameplate rating greater than or equal to 50 MVA, connected at the point of interconnection[2] with rating greater than or equal to 100 kV.~~
- ~~For each plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV:~~
  - ~~Each unit with a gross nameplate rating greater than or equal to 20 MVA; and~~

[3] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

[4] ~~The common transmission bus voltage level at which the generator step up transformer is connected.~~

- ~~The remainder of the plant as an aggregate.~~

~~For all interconnections:~~

- ~~Any technically justified[5] unit requested by the Planning Coordinator.~~

Effective Date

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter, four years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval.
- Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2 By the first day of the first calendar quarter, ten years following applicable regulatory approval.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.

[5] ~~A technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response.~~

Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2 By the first day of the first calendar quarter, ten years following Board of Trustees adoption.~~In those jurisdictions where regulatory approval is required:~~

~~By the first day of the first calendar quarter, four years following applicable regulatory approval:~~

- ~~Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.~~
- ~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6.~~

~~By the first day of the first calendar quarter, six years following applicable regulatory approval:~~

- ~~Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.~~

~~By the first day of the first calendar quarter, ten years following applicable regulatory approval:~~

- ~~Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2.~~

~~In those jurisdictions where no regulatory approval is required:~~

~~By the first day of the first calendar quarter, four years following Board of Trustees adoption:~~

- ~~Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.~~
- ~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6.~~

~~By the first day of the first calendar quarter, six years following Board of Trustees adoption:~~

- ~~Each Generator Owner shall ensure at least 50% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2.~~

~~By the first day of the first calendar quarter, ten years following Board of Trustees adoption:~~

- ~~Each Generator Owner shall ensure 100% of its applicable units are compliant with Requirement R2.~~

Consideration for Early Compliance

Existing excitation control system and plant volt/var control1 model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements ten years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This second posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop third version draft standard.	August 2011 – February 2012
2. Post response to comments and third version draft revision of standard for 30 day comment and successive ballot period.	February – March 2012
3. Develop responses to successive ballot comments.	April – June 2012
4. Post response to comments.	July 2012
5. Conduct recirculation ballot.	July 2012
7. BOT adoption.	August 2012
8. File with regulatory authorities.	October 2012

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Performance During Frequency and Voltage Excursions

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure generating units remain connected during frequency and voltage excursions, and ensure expected generating unit performance during frequency and voltage excursions, is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. Each Generator Owner shall verify that at least 33 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption.

   5.2. Each Generator Owner shall verify that at least 66 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption.

   5.3. Each Generator Owner shall verify that 100 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption.

   5.4. Requirement R5 shall be effective on the first day of the first calendar quarter six years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six years following Board of Trustees adoption.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not trip within the "no trip zone" of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit.[2] *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec.

1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its new or existing generating unit or generating plant shall set its protective relaying such that it does not trip as a result of a voltage excursion (at the point of interconnection[3]) that remains within the "no trip zone" of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit or generating plant.: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. If a Transmission Planner's study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] To include generators under construction, generators with an executed interconnection agreement or Power Purchase Agreement by the effective date of this standard, or generators with an executed equipment purchase contract and scheduled delivery of major components within 2 years of the effective date of Requirement R5 of Version 1 of this standard.

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

meet the Transmission Planner's voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.

2.1.2. Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2.

2.1.3. If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

R3. Each Generator Owner of an existing generating unit or generating plant shall document each equipment limitation (excluding generator frequency and voltage protective relay limitations) that prevents a generating unit or generating plant, from meeting the criteria in Requirements R1 or R2 including study results, experience from an actual event, or manufacturer's advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.
- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).

R4. Each Generator Owner of an existing generating unit or generating plant shall provide an estimate of that unit's performance during Frequency/Voltage Excursions to each requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit or generating plant) within 60 calendar days of receipt of a written request, to ensure the accuracy of planning studies and system modeling studies. The estimate shall include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection described by dynamic simulation provided by the Transmission Planner. If the Generator Owner expects the existing unit, generating plant will remain connected for longer than 10 minutes, the estimate should indicate the existing unit or generating plant is not expected to trip.

4.2. Identification of the bases for the estimates developed for 4.1 which may include, but is not limited to: experience, actual event histories, or sound engineering judgment.

R5. Each Generator Owner shall design, build, and maintain its new [4] unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion at the point of interconnection, caused by an event on the transmission system external to the generating plant, within the parameters set forth in PRC-024 Attachments 1 and 2 and in accordance with the following conditions and exceptions: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

5.1. (condition) When the generating unit or generating plant is operating at or above the minimum sustainable generation threshold.

5.1.1. For a generating plant consisting of multiple units with total generation greater than 75 MVA (gross aggregate nameplate rating), when the generating plant is producing at least 20 percent of the plant's aggregate nameplate capacity.

5.2. (exception) For a new generating plant consisting of multiple units less than 20 MVA each with total plant generation greater than75 MVA (gross aggregate rating), 10 percent of the individual generating units may disconnect as a result of the frequency or voltage excursion.

5.3. (exception) A generating unit or generating plant may operate to a less stringent voltage ride-through performance criterion than the duration curve identified in PRC-024 Attachment 2 based on the location-specific voltage recovery characteristics if provided by the Transmission Planner as described in Requirement 2, Part 2.1.1.

5.4. (exception) A generating unit or generating plant may trip if this action is designed as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).

5.5. (exception) A generating unit or generating plant may trip if clearing a system fault necessitates disconnecting the generating unit or generating plant.

[4] Excluding generators in service prior to the effective date of Requirement R5 of Version 1 of this standard and excluding generators referenced in Footnote 2.

5.6. (exception) A generating unit or generating plant may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation. The Reliability Coordinator may retroactively grant a temporary exemption for an equipment limitation identified following a plant trip caused by a frequency or voltage excursion if the Generator Owner develops and implements an acceptable Mitigation Plan.

5.7. (exception) A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

R6. Each Generator Owner shall provide its generator protection trip settings to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner (that monitors or models the associated unit), within 30 calendar days of receipt of a written request for the data, and within 30 calendar days of any change to those trip settings, to ensure the accuracy of planning studies and system modeling. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence such as dated setting sheets, calibration sheets, or other documentation, that generator frequency protective relays have been set in accordance with Requirement R1.

M2. Each Generator Owner shall have evidence such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies, that generator voltage protective relays have been set in accordance with Requirement R2.

M3. Each Generator Owner shall have evidence that it has documented and communicated any equipment limitations (Protection System excluded) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

M4. Each Generator Owner shall have evidence such as a copy of the performance report and correspondence, such as dated e-mails, or other documentation that an estimate of the performance of its existing generating unit(s) as a result of a Frequency Excursion or Voltage Excursion has been communicated in accordance with Requirement R4, and copies of any requests it has received for that information.

M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a Frequency Excursion or Voltage Excursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip.

M6. Each Generator Owner shall have evidence such as dated e-mails, correspondence or other evidence that it communicated generator protective relay settings to a requesting entity within 30 calendar days of a request or change in setting(s) in accordance with Requirement R6 and copies of any requests it has received for that information..

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest evidence of Requirement R1 through R6, Measure M1 through M6; and shall retain prior evidence for 3 calendar years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generator has no documented and communicated technical limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying has no documented and communicated technical limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the conditions specified in Requirement R2
R3	The Generator Owner documented the non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its	The Generator Owner documented the non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its	The Generator Owner documented the non-protection system equipment limitation that prevented it from meeting the criteria in h Requirement R1 or R2 and communicated the documented limitation to its	The Generator Owner failed to document any non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 30 calendar days but less than or equal to 40 calendar days of identifying the limitation.	Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 40 calendar days but less than or equal to 50 calendar days of identifying the limitation.	Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 50 calendar days but less than or equal to 60 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 61 calendar days of identifying the limitation.
R4	The Generator Owner provided an estimate of a unit's performance more than 30 calendar days but less than or equal to 40 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 40 calendar days but less than or equal to 50 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 50 calendar days but less than or equal to 60 calendar days of a written request. OR The Generator Owner failed to include documentation for one of the Parts specified in Requirement R4, Parts 4.1 and 4.2.	The Generator Owner failed to provide an estimate of a unit's performance within 61 calendar days of a written request. OR The Generator Owner failed to include any of the documentation specified in Requirement R4, Parts 4.1 and 4.2.
R5	N/A	N/A	N/A	The Generator Owner's generator tripped due to a Frequency Excursion within the no-trip parameters set forth in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1. OR The Generator Owner's generator tripped due to a Voltage Excursion within the no-trip parameters set forth in Attachment 2.
R6	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than 30 calendar days but less than or equal to 40 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings more than 30 calendar days but less than or equal to 40 calendar days of a written request.	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than 40 calendar days but less than or equal to 50 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings more than 40 calendar days but less than or equal to 50 calendar days of a written request.	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than 50 calendar days but less than or equal to 60 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings more than 50 calendar days but less than or equal to 60 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings as specified by Requirement R6 within 60 calendar days of any change to those trip settings or limitations. OR The Generator Owner failed to provide trip settings within 60 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

Version History

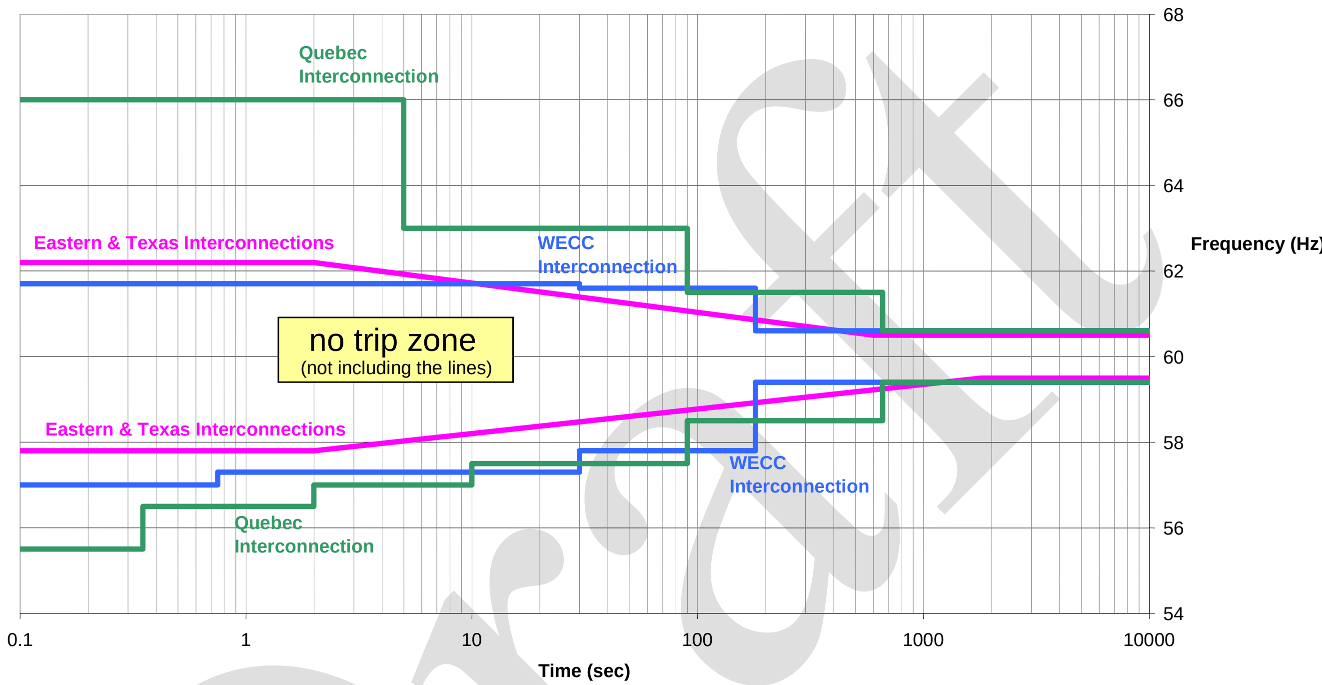
Version	Date	Action	Change Tracking

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern and Texas Interconnections

High Frequency Duration		Low Frequency Duration	
Time (Sec)	**Frequency (Hz)**	**Time (Sec)**	**Frequency (Hz)**
0 - 2	62.2	0 – 2	57.8
2 – 600	62.41 – 0.686log(t)	2 – 1800	57.63 + 0.575log(t)
> 600	60.5	> 1800	59.5

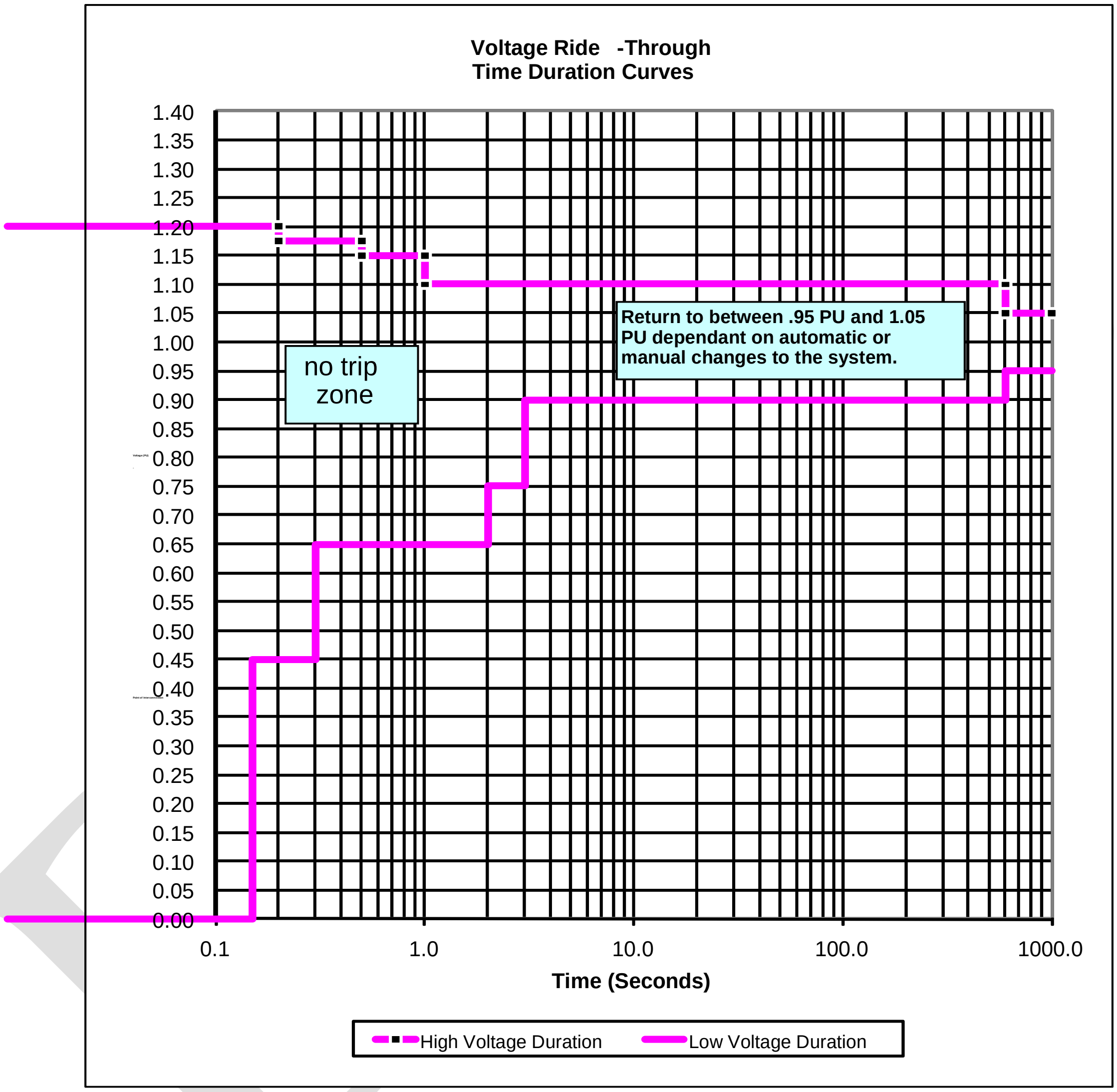
WECC Interconnection

High Frequency Duration		Low Frequency Duration	
Time (Sec)	Frequency (Hz)	Time (Sec)	Frequency (Hz)
0 – 30	61.7	0 – 0.75	57.0
30 – 180	61.6	0.75 – 30	57.3
> 180	60.6	30 – 180	57.8
		> 180	59.4

Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Time (Sec)	Frequency (Hz)	Time (Sec)	Frequency (Hz)
0 – 5	66.0	0 – 0.35	55.5
5 – 90	63.0	0.35 – 2	56.5
90 – 660	61.5	2 – 10	57.0
> 660	60.6	10 – 90	57.5
		90 – 660	61.5
		> 660	60.6

PRC-024— Attachment 2



Curve Data Points:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Time (Sec)	Voltage (p.u.)	Time (Sec)	Voltage (p.u.)
0.20	1.200	0.15	0.000
0.50	1.175	0.30	0.450
1.00	1.150	2.00	0.650
600	1.100	3.00	0.750
		600	0.900

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum crest phase-to-ground or phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

6. Use the following assumptions to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating,
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals).
7. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
8. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.

Proposed Action Plan and Description of Current Draft:

This is the ~~second~~third draft of the ~~proposed~~ standard ~~including~~and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This second posting ~~of the standard~~ is for a 30-day ~~formal~~ comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. ~~Post first~~Develop responses to comments and develop third version draft ~~revision of~~ standard.	~~April-May~~August 2011 – February 2012
2. Post response to comments and third version draft revision of standard for 30 day comment and successive ballot period.	~~July – August 2011~~February – March 2012
3. ~~Post response~~Develop responses to successive ballot comments ~~and request authorization to ballot the revised standard~~.	~~September – October 2011~~April – June 2012
~~4. Conduct initial ballot.~~	~~November 2011~~
~~5~~4. Post response to comments.	~~December 2011~~July 2012

~~6~~5. Conduct recirculation ballot.	~~January~~July 2012
7. BOT adoption.	~~February~~August 2012
8. File with regulatory authorities.	~~March~~October 2012

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

~~**Frequency Excursion** – an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz.~~

~~**Voltage Excursion** – an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage.~~

None

A. Introduction

1. **Title:** Generator Performance During Frequency and Voltage Excursions

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure generating units remain connected during frequency and voltage excursions, and ensure expected generating unit performance during frequency and voltage excursions, is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.

4. **Applicability:**

   ~~**1.1.**~~**4.1.** Generator Owner

5. **Effective Date:**

   ~~**1.2.**~~**5.1.** ~~The~~Each Generator Owner shall verify that at least 33 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption~~:~~.

      ~~**1.2.1**~~ Each Generator Owner shall verify that at least ~~33%~~66 percent of its applicable units are fully compliant with ~~this standard.~~

   ~~**1.3.**~~**5.2.** ~~The~~Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption~~:~~.

      ~~**1.3.1**~~ Each Generator Owner shall verify that ~~at least 66%~~100 percent of its applicable units are fully compliant with ~~this standard.~~

   ~~**1.4.**~~**5.3.** ~~The~~Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption~~:~~.

      ~~**1.4.1** Each Generator Owner shall verify that 100% of its applicable units are fully compliant with this standard.~~

   5.4. Requirement R5 shall be effective on the first day of the first calendar quarter six years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six years following Board of Trustees adoption.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying~~ ~~[1] activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not ~~to~~ trip ~~per~~within the ~~following operating conditions and relay settings~~"no trip zone" of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated ~~a non-protection system~~each equipment limitation in accordance with Requirement R3 for an existing generating unit.[2] *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

~~1.1. When operating~~A generating unit or generating plant is allowed to trip within ~~a frequency range of 59.5 Hz to 60.5 Hz, inclusive.~~

~~1.2. During~~ the ~~off-nominal frequency excursions specified in PRC-024 Attachment 1.~~

~~1.3. By instantaneous under frequency relays set at a frequency higher than 57.8 Hz.~~

~~1.4. By instantaneous over frequency relays set at a frequency lower than 62.2 Hz.~~

~~1.5.~~1.1. ~~When~~"no trip zone" if the ~~transmission system~~ frequency rate of change is ~~less~~more than 2.5 Hz/~~second.~~ sec.

1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its new or existing generating unit or generating plant ~~or Facility~~ shall set its protective relaying such that it does not ~~to~~ trip as a result of a voltage excursion (at the point of

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (~~includes~~including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within ~~excitation controls~~control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] To include generators under construction, generators with an executed interconnection agreement or Power Purchase Agreement by the effective date of this standard, or generators with an executed equipment purchase contract and scheduled delivery of major components within 2 years of the effective date of ~~version~~Requirement R5 of Version 1 of this standard.

interconnection~~)~~[3]) that remains within the "no trip zone" of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and communicated ~~a~~each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit or generating plant ~~or generating Facility:~~.: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. When operating within 95~~%~~ percent to 105~~%~~ percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

~~**2.1.1.** For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, not to exceed 9 cycles.~~

~~**2.1.2.**~~**2.1.1.** If a Transmission Planner's study (based on the location specific voltage recovery characteristics) ~~recommends~~allows less stringent voltage relay settings than those ~~in~~required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner's ~~settings~~voltage recovery characteristics or the ~~settings~~characteristics in PRC-024 Attachment 2.

~~**2.1.3.**~~**2.1.2.** ~~If~~Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) ~~includes tripping a generator after fault initiation, then setting the SPS or RAS relays to trip the generator even if~~ is acceptable in the "no trip zone" ~~in~~of PRC-024 Attachment 2 ~~is acceptable~~.

~~**2.1.4.**~~**2.1.3.** If clearing a system fault necessitates disconnecting a generator, ~~then setting relays to trip the generator even if operating~~this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2 ~~is acceptable~~.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

R3. Each Generator Owner of an existing generating unit or generating plant ~~or Facility~~ shall document each ~~non-protection system~~ equipment limitation (excluding generator frequency and voltage protective relay limitations) that prevents a generating unit~~,~~ or generating plant~~, or Facility~~ from meeting the criteria in ~~Requirement~~Requirements R1 or R2 ~~and~~ including study results, experience from an actual event, or manufacturer's advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

~~R3.~~3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. ~~The equipment limitation expires~~ The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.
- The ~~generating unit continuous~~equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating ~~increases ≥~~greater than 10~~%.~~

~~*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~

~~R4.~~~~•~~ ~~Within 90 calendar days of receipt of a written inquiry~~ percent (cumulative from the ~~Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner regarding an equipment limitation identified in accordance with Requirement R3, the Generator Owner shall provide a written response to the entity that submitted the inquiry.~~ first effective date of this Standard).

~~R5.~~**R4.** Each Generator Owner of an existing generating unit or generating plant ~~or generating Facility~~ shall provide an estimate of that unit's performance during Frequency/Voltage Excursions to ~~the~~each requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit or generating plant) within ~~30~~60 calendar days of receipt of a written request, to ensure the accuracy of planning studies and system modeling studies. The ~~documentation~~estimate shall include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~5.1.~~ An estimate of the time duration the existing generating unit or generating plant ~~or Facility~~ will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a ~~Frequency Excursion~~frequency excursion or a voltage excursion defined by the ~~curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2 or the~~ voltage or frequency profile at the ~~Point of Interconnection for the generating unit or generating plant or Facility~~point of ~~the most severe normally-cleared Zone 1 fault~~interconnection described by dynamic simulation provided by the Transmission Planner ~~if this profile is less stringent~~. If the Generator Owner expects the existing unit, generating plant will remain connected for longer than 10 minutes, the ~~curves in Attachment 2.~~

~~5.2.~~4.1. ~~An estimated probability in 25% increments that~~estimate should indicate the existing unit or generating plant ~~or generating Facility will remain connected during a Frequency Excursion defined by the curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2 or the voltage profile at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault described by dynamic simulation provided by the Transmission Planner if this profile is less stringent than the curves in Attachment 2.~~ is not expected to trip.

~~5.3.~~4.2. Identification of the ~~basis~~bases for the estimates developed for ~~5~~4.1~~ and 5.2~~ which may include, but is not limited to: experience, actual event histories, or sound engineering judgment.

~~R6.~~R5. Each Generator Owner shall design, build, and maintain its new [4] unit or new generating plant ~~or generating Facility~~ so that it will not trip due to a ~~Frequency Excursion or Voltage Excursion~~frequency excursion or voltage excursion at the ~~Point~~point of ~~Interconnection~~interconnection, caused by an event on the transmission system external to the generating plant, within the parameters set forth in PRC-024 Attachments 1 and 2 and in accordance with the following conditions and exceptions: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

~~6.1.~~5.1. (condition) When the generating unit or generating plant ~~or generating Facility~~ is operating at or above the minimum sustainable generation threshold.

~~6.1.1.~~5.1.1. For a generating plant ~~or generating Facility~~ consisting of multiple units with total generation ~~>~~greater than 75 MVA (gross aggregate nameplate rating), when the ~~Facility~~ generating plant is producing at least 20~~%~~ percent of the ~~Facility's rated~~plant's aggregate nameplate capacity ~~and the voltage support equipment is in service~~.

~~6.2.~~5.2. (~~condition~~exception) For a new generating plant ~~or generating Facility~~ consisting of multiple units less than 20 MVA each with total ~~Facility~~plant generation ~~> 75~~greater than75 MVA (gross aggregate rating), ~~at least 90%~~10 percent of the individual generating units ~~shall remain connected~~may disconnect as a result of the frequency or voltage excursion.

~~6.3.~~5.3. (exception) A generating unit or generating plant ~~or generating Facility~~ may operate to a less stringent voltage ride-through performance criterion than the duration curve identified in PRC-024 Attachment 2 based on the location~~-~~-specific voltage recovery characteristics ~~as specified~~if provided by the Transmission Planner as described in Requirement 2, Part 2.1.1.

[4] Excluding generators in service prior to the effective date of ~~version~~Requirement R5 of Version 1 of this standard and excluding generators referenced in Footnote 2.

~~6.4.~~5.4. (exception) A generating unit or generating plant~~ or generating Facility~~ may trip if this action is designed as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).

~~6.5.~~5.5. (exception) A generating unit or generating plant ~~or generating Facility~~ may trip if clearing a system fault necessitates disconnecting the generating unit or generating plant~~ or generating Facility~~.

~~6.6.~~5.6. (exception) A generating unit or generating plant~~ or generating Facility~~ may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation. The Reliability Coordinator may retroactively grant a temporary exemption for an equipment limitation identified following a plant trip caused by a frequency or voltage excursion if the Generator Owner develops and implements an acceptable Mitigation Plan.

~~6.7.~~5.7. (exception) A generating unit or generating plant ~~or generating Facility~~ may trip if the protective functions (such as out-~~-~~of-~~-~~step or loss-~~-~~of-~~-~~field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

~~R7.~~R6. Each Generator Owner shall provide its generator protection trip settings to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner (that monitors or models the associated unit~~) its generator protection trip settings as specified by Requirements R1 and R2, and documented equipment limitations as specified by Requirement R3~~), within 30 calendar days of receipt of a written request for the data, and within 30 calendar days of any change to those trip settings~~ or limitations and within 30 calendar days of a written request for the data~~, to ensure the accuracy of planning studies and system modeling. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

~~R8.~~M1. Each Generator Owner ~~has~~shall have evidence such as dated setting sheets, calibration sheets, or other documentation, that generator frequency protective relays have been set in accordance with Requirement R1.

~~R9.~~M2. Each Generator Owner ~~has~~shall have evidence such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies, that generator voltage protective relays have been set in accordance with Requirement R2.

~~R10.~~M3. Each Generator Owner ~~has~~shall have evidence that it has documented and communicated any equipment limitations (Protection System excluded) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

~~M1.~~ Each Generator Owner ~~has evidence such as dated e-mails, mail receipts or other evidence that it provided a written response to an inquiry regarding equipment limitations to a requesting entity within 90 calendar days of a request in accordance with Requirement R4.~~

~~R11.~~**M4.** ~~Each Generator Owner has~~shall have evidence such as a copy of the performance report and correspondence, such as dated e-mails,~~ mail receipts~~ or other documentation that an estimate of the performance of its existing generating unit(s) as a result of a Frequency Excursion or Voltage Excursion has been communicated in accordance with Requirement ~~R5~~R4, and copies of any requests it has received for that information.

~~R12.~~**M5.** Each Generator Owner ~~has~~shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records~~ or a trip report indicating,~~ showing that each unit trip did not result from a Frequency Excursion or Voltage Excursion as specified in Requirement ~~R6~~R5, or evidence that a listed exception applied, or provide an attestation that the generating unit~~,~~ or generating plant~~ or Facility~~ did not trip.

~~R13.~~**M6.** Each Generator Owner ~~has~~shall have evidence such as dated e-mails, ~~mail receipts~~correspondence or other evidence that it communicated generator protective relay settings~~ or equipment limitations~~ to a requesting entity within 30 calendar days of a request or change in setting(s) in accordance with Requirement ~~R7.~~R6 and copies of any requests it has received for that information..

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest evidence of Requirement R1 through ~~R7~~R6, Measure M1 through ~~M7~~M6; and shall retain prior evidence for 3 calendar years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance ~~Violation~~ Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generator has no documented and communicated technical limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1~~, Parts 1.1 through 1.5.~~
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying has no documented and communicated technical limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not ~~to~~ trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the ~~operating~~ conditions ~~and relay settings~~ specified in Requirement R2
R3	The Generator Owner documented the non-protection system equipment limitation that ~~prevents compliance with~~prevented it from meeting	The Generator Owner documented the non-protection system equipment limitation that ~~prevents compliance with~~prevented it from meeting	The Generator Owner documented the non-protection system equipment limitation that ~~prevents compliance with~~prevented it from meeting	The Generator Owner failed to document any non-protection system equipment limitation that ~~prevents compliance with~~prevented it from meeting

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	the criteria in Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 30 calendar days but less than or equal to 40 calendar days of identifying the limitation.	the criteria in Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 40 calendar days but less than or equal to 50 calendar days of identifying the limitation.	the criteria in h Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 50 calendar days but less than or equal to 60 calendar days of identifying the limitation.	the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 61 calendar days of identifying the limitation.
~~R4~~	~~The Generator Owner provided a written response to an equipment limitation inquiry more than 90 calendar days but less than or equal to 100 calendar days of a written request.~~	~~The Generator Owner provided a written response to an equipment limitation inquiry more than 100 calendar days but less than or equal to 110 calendar days of a written request.~~	~~The Generator Owner provided a written response to an equipment limitation inquiry more than 110 calendar days but less than or equal to 120 calendar days of a written request.~~	~~The Generator Owner failed to provide a written response to an equipment limitation inquiry within 121 calendar days of a written request.~~
~~R5~~R4	The Generator Owner provided an estimate of a unit's performance more than 30 calendar days but less than or equal to 40 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 40 calendar days but less than or equal to 50 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 50 calendar days but less than or equal to 60 calendar days of a written request.	The Generator Owner failed to provide an estimate of a unit's performance within 61 calendar days of a written request. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		~~OR~~ ~~The Generator Owner failed to include documentation for one of the Parts specified in Requirement R5, Parts 5.1 through 5.3.~~	OR The Generator Owner failed to include documentation for ~~two~~one of the Parts specified in Requirement ~~R5~~R4, Parts ~~5~~4.1 ~~through 5.3~~and 4.2.	The Generator Owner failed to include any of the documentation specified in Requirement ~~R55~~R4, Parts ~~5~~4.1 ~~through 5.3.~~and 4.2.
~~R6~~R5	N/A	N/A	N/A	The Generator ~~Owner failed to demonstrate its new unit or new generating plant or generating Facility did not trip~~ Owner's generator tripped due to a Frequency Excursion within the no-trip parameters set forth in ~~Requirement 6.~~Attachment 1. OR The Generator ~~Owner failed to demonstrate its new unit or new generating plant or generating Facility did not trip~~ Owner's generator tripped due to a Voltage Excursion within the no-trip parameters set forth in Attachment 2.
~~R7~~R6	The Generator Owner provided its generator protection trip settings as specified by	The Generator Owner ~~provide~~provided its generator protection trip settings as	The Generator Owner ~~provide~~provided its generator protection trip settings as	The Generator Owner failed to provide its generator protection trip settings as specified by

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Requirements R1 and R2, and documented equipment limitations as specified by~~ Requirement ~~R3~~R6 more than 30 calendar days but less than or equal to 40 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings ~~or equipment limitations~~ more than 30 calendar days but less than or equal to 40 calendar days of a written request.	specified by ~~Requirements R1 and R2, and documented equipment limitations as specified by~~ Requirement ~~R3~~R6 more than 40 calendar days but less than or equal to 50 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings ~~or equipment limitations~~ more than 40 calendar days but less than or equal to 50 calendar days of a written request.	specified by ~~Requirements R1 and R2, and documented equipment limitations as specified by~~ Requirement ~~R3~~R6 more than 50 calendar days but less than or equal to 60 calendar days of any change to those trip settings or limitations. OR The Generator Owner provided trip settings ~~or equipment limitations~~ more than 50 calendar days but less than or equal to 60 calendar days of a written request.	~~Requirements R1 and R2, and documented equipment limitations as specified by~~ Requirement ~~R3~~R6 within ~~61~~60 calendar days of any change to those trip settings or limitations. OR The Generator Owner failed to provide trip settings ~~or equipment limitations~~ within ~~61~~60 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

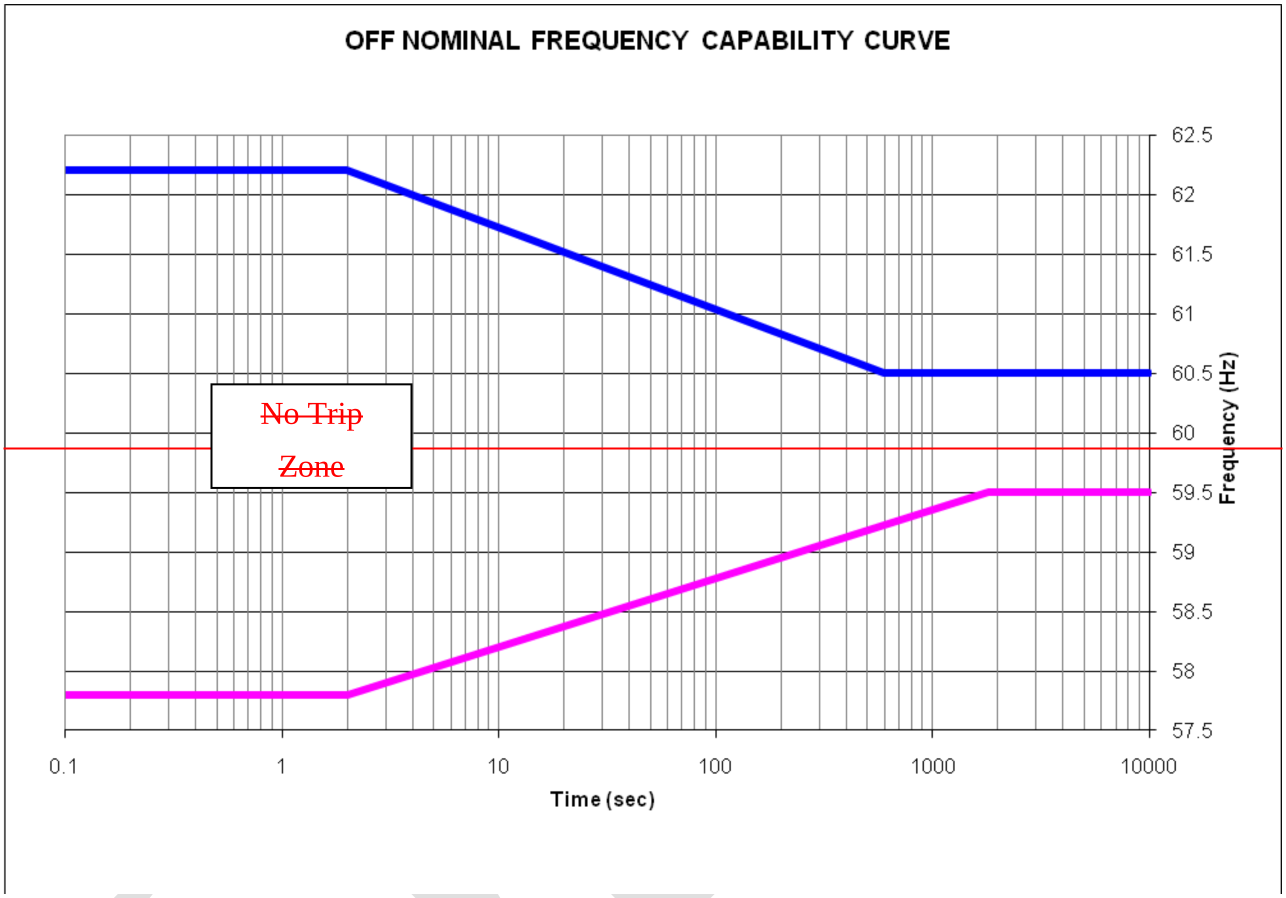
Version History

Version	Date	Action	Change Tracking

G. References

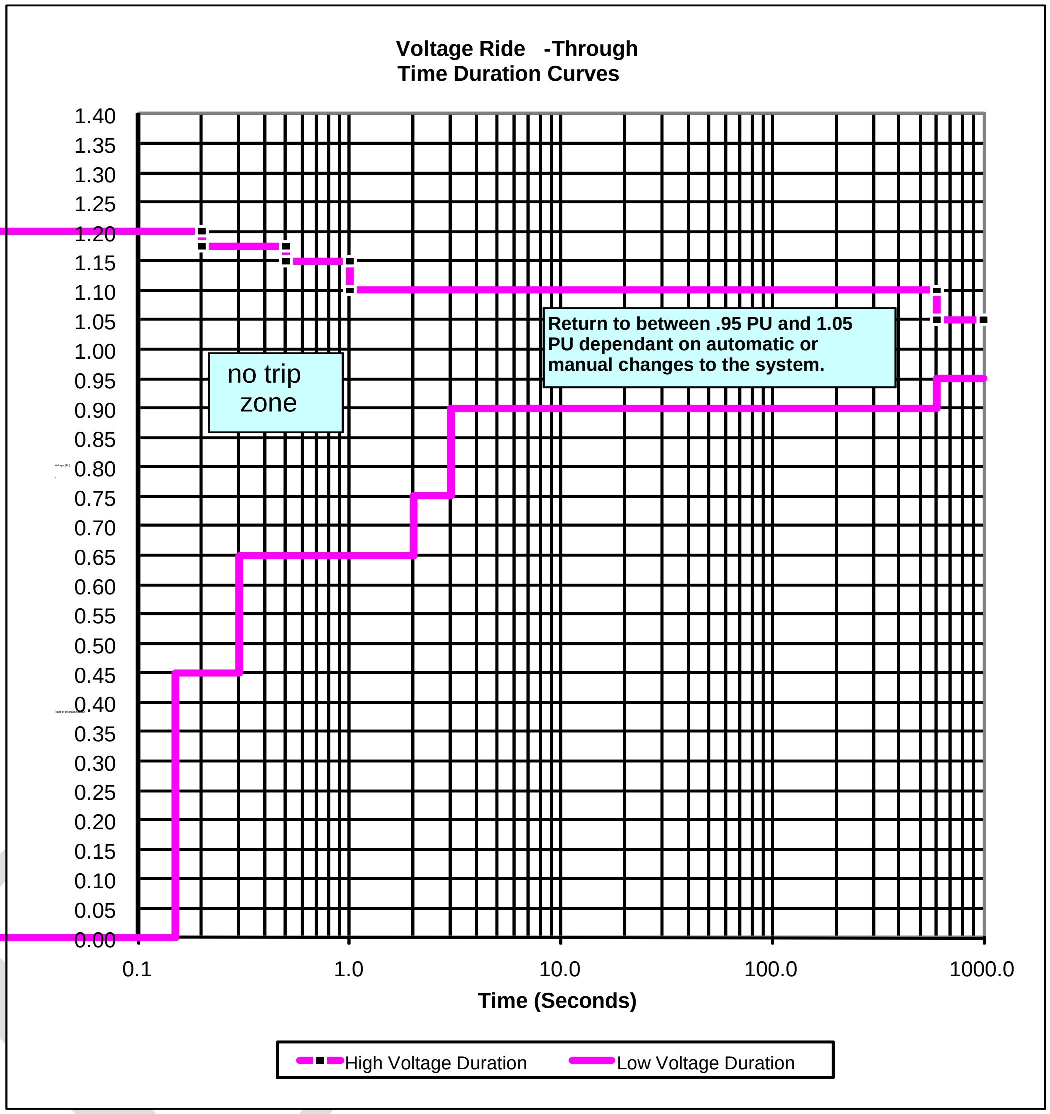
1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

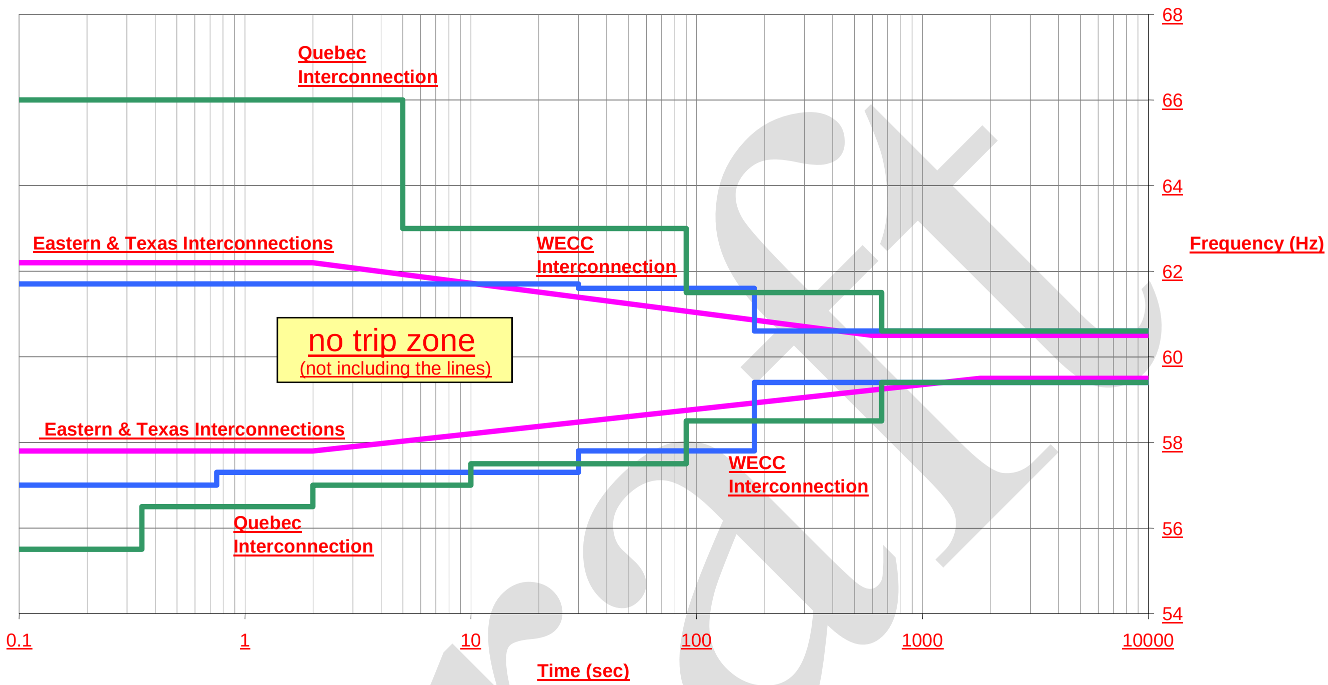


~~**Frequency (hertz)**~~	~~57.8~~	~~59.5~~	~~62.2~~	~~60.5~~
~~**Time (seconds)**~~	~~0 to 2~~	~~Over 1800~~	~~0 to 2~~	~~Over 600~~

~~PRC-024 — Attachment 2~~



OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern and Texas Interconnections

~~HVRT DURATION~~High Frequency Duration		Low Frequency Duration	
Time (Sec)	~~Voltage (p.u.)~~Frequency (Hz)	Time (Sec)	Frequency (Hz)
~~0.20~~	~~1.200~~		
~~0.50~~	~~1.175~~		
~~1.00~~	~~1.150~~		
~~600~~	~~1.100~~		
~~LVRT DURATION~~			
~~Time (Sec)~~	~~Voltage (p.u.)~~		
0.~~15~~ - 2	62.2	0.~~000~~ – 2	57.8
2 – 600	62.41 – 0.~~30~~686log(t)	2 – 1800	57.63 + 0.~~450~~575log(t)
~~2.00~~	~~0.650~~		
~~3.00~~	~~0.750~~		
> 600	~~0.900~~60.5	> 1800	59.5

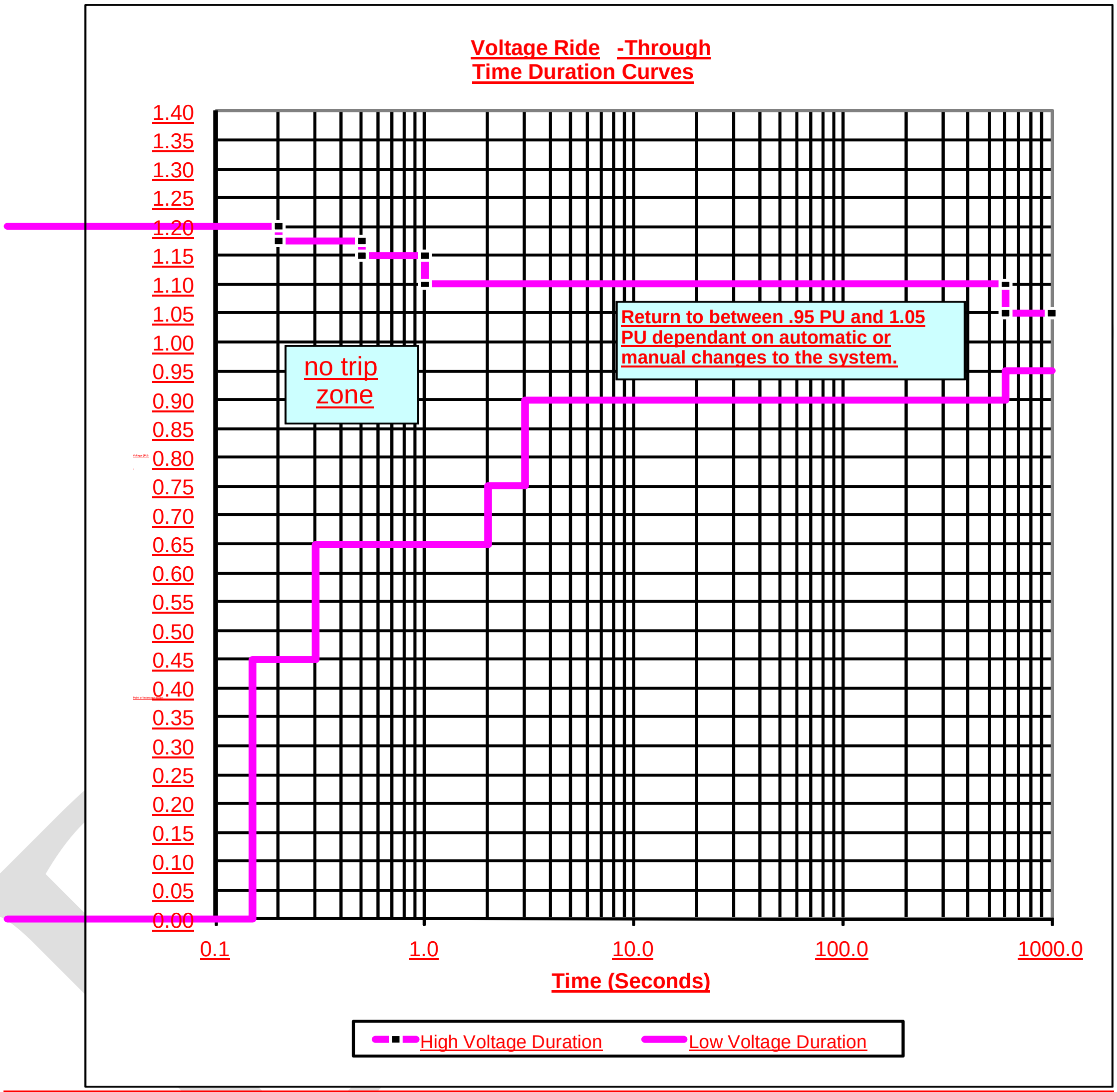
WECC Interconnection

High Frequency Duration		Low Frequency Duration	
Time (Sec)	**Frequency (Hz)**	**Time (Sec)**	**Frequency (Hz)**
0 – 30	61.7	0 – 0.75	57.0
30 – 180	61.6	0.75 – 30	57.3
> 180	60.6	30 – 180	57.8
		> 180	59.4

Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Time (Sec)	**Frequency (Hz)**	**Time (Sec)**	**Frequency (Hz)**
0 – 5	66.0	0 – 0.35	55.5
5 – 90	63.0	0.35 – 2	56.5
90 – 660	61.5	2 – 10	57.0
> 660	60.6	10 – 90	57.5
		90 – 660	61.5
		> 660	60.6

PRC-024— Attachment 2



Curve Data Points:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Time (Sec)	Voltage (p.u.)	Time (Sec)	Voltage (p.u.)
0.20	1.200	0.15	0.000
0.50	1.175	0.30	0.450
1.00	1.150	2.00	0.650
600	1.100	3.00	0.750
		600	0.900

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the ~~scheduled operating~~base voltage ~~as measured~~specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).

2. The curves depicted ~~apply to a~~were derived based on three-phase transmission system zone 1 ~~fault~~faults with Normal Clearing not exceeding 9 cycles.

3. ~~When~~The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES~~ is within~~. For example, if the voltage ~~boundaries of these curves, the generator~~exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage~~ protective relaying will not~~ , and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the ~~generator.~~curve.

4. The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal.

5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum crest phase-to-ground or phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

~~5.~~6. Use the following assumptions ~~if basing~~to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:

   a. All of the units connected to the same transformer are online and operating,

   b. All of the units are at full nameplate real-power output.

   c. Power factor is 0.95 lagging~~.~~ (i.e. supplying reactive power to the system) as measured at the generator terminals).

   ~~d. Scheduled voltage is measured at the point of interconnection.~~

~~6.~~7. ~~Calculate~~Evaluate voltage protection relay settings ~~to comply with these curves~~ assuming that~~ any~~ additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.

~~7.~~8. ~~Calculate~~Evaluate voltage protection relay settings~~ to comply with these curves,~~ accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Performance During Frequency and Voltage Excursions

Approvals Required

PRC-024-1 – Generator Performance During Frequency and Voltage Excursions.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

Each Generator Owner shall verify that at least 33 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption.

Each Generator Owner shall verify that at least 66 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption.

Each Generator Owner shall verify that 100 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption. Requirement R5 shall be effective on the first day of the first calendar quarter six years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six years following Board of Trustees adoption.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, R4, and R6 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a three-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than three years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Requirement R5 involves the performance of complete generation facilities (i.e. the prime mover, its fuel supply, and all auxiliary systems). To date, most Generator Owners have not specified this type of performance and the engineering companies designing generating facilities have not designed the facilities to ride through frequency and voltage excursions of the severity specified in PRC-024. In order to allow Generator Owners and architect/engineering companies time to develop new designs to meet R5, the SDT allows six years from regulatory approval for implementation.

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for PRC-024-1, Generator Performance During Frequency and Voltage Excursions

Approvals Requested:

PRC-024-1 – Generator Performance During Frequency and Voltage Excursions

Definitions:

> ~~**Frequency Excursion** – an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz.~~
>
> ~~**Voltage Excursion** – an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage.~~**None**

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of PRC-024-1:

- Generator Owner

Effective Date

Each Generator Owner shall verify that at least 33 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption.

Each Generator Owner shall verify that at least 66 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption.

Each Generator Owner shall verify that 100 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption.

Requirement R5 shall be effective on the first day of the first calendar quarter six years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six years following Board of Trustees adoption.

~~The first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption:~~

- ~~Each Generator Owner shall verify at least 33% applicable units fully compliant with this standard.~~

~~The first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption:~~

- ~~Each Generator Owner shall verify at least 66% applicable units fully compliant with this standard.~~

~~The first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption:~~

- ~~Each Generator Owner shall verify 100% applicable units fully compliant with this standard~~

~~The phasing allows Generator Owners to effect any needed changes to the protective system settings during normally scheduled outages.~~

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1~~, R4~~ will also go into effect.

Justification of Phasing

Requirements R1, R2, R3, R4, and R6 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a three-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than three years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Requirement R5 involves the performance of complete generation facilities (i.e. the prime mover, its fuel supply, and all auxiliary systems). To date, most Generator Owners have not specified this type of performance and the engineering companies designing generating facilities have not designed the facilities to ride through frequency and voltage excursions of the severity specified in PRC-024. In order to allow Generator Owners and architect/engineering companies time to develop new designs to meet R5, the SDT allows six years from regulatory approval for implementation.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2007-09 Generator Verification

MOD-026-1 and PRC-024-1

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to MOD-026-1 and PRC-024-1. Comments must be submitted by **March 29, 2012**. If you have questions please contact Stephen Crutchfield at Stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The Generator Verification Standard Drafting Team posted MOD-026-1, Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions, and PRC-024-1, Generator Performance During Frequency and Voltage Excursions, from June 15 through August 1, 2011 for a 45-day concurrent comment/ballot period. Stakeholders were asked to comment on several aspects of the standard.

MOD-026-1

The GVSDT asked stakeholders if they believed any additional generation configurations should be considered for applicability under this standard. None of the comments identified other generation configurations/types that should be covered in the Applicability. Several commenters recommend making the standard applicability match the compliance registry, while other commenters recommend removing the requirement to verify small generator units from the standard applicability. The SDT believes:

- The standard is drafted to provide the proper cost/benefit balance for performing generator verification.

- It is not necessary to have models verified for all units listed in the compliance registry.

- Proposed applicability thresholds will substantially improve the accuracy of the excitation models and associated reliability-based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

The SDT recognizes that the excitation system model and modeling data is already captured by the MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database. Field testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation. Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds which correspond to at least 80% of the connected MVA in each

Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification. Concern was raised that the language of R5 could require verification of units with ratings less than the thresholds specified in the registry criteria. The SDT asserts that any unit not included in the standard Applicability and deemed to require verification as justified by the Planning Coordinator must, by definition, satisfy the Registry Criteria threshold established. The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit. This is not the case.

A few commenters expressed concern that the standard does not require the Generator Owner to notify the Transmission Owner of new equipment and provide the Transmission Planner preliminary models based on OEM design data. The SDT reminds that the scope of the draft standard is model verification, which can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process.
Also in response to industry comments, the SDT has inserted a footnote in the standard to make clear that standby generator models are not required to be verified.

The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers.

The GVSDT received many comments concerning various aspects of the standard. As a result of these comments, the SDT has made a number of modifications to the standard including:

1) Correcting several VSL grammatical errors and ensuring consistency between the VSL "increment for tardiness" time period specified and the requirement language.

2) An additional condition was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed-loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations, other than switching capacitor and reactor banks in and out of service.

3) The format and column information of Attachment 1 has been revised for clarity.

4) The typographical errors in R2.1.1 language has been corrected to clearly state expectation that, "The unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of Interconnection from either a staged test or a measured system disturbance."

5) The language of R2.1.4 has been revised to align with the style of R2.1.6.

6) Several commenters expressed concern with the new Requirement R5 added to the standard giving the Planning Coordinator authority to require a model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the requirement could be misused inappropriately. In addition, R5 language has been revised for clarity.

7) To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).

8) There was some confusion regarding the treatment of small units at plants. The SDT modified the language in the Applicability/Facilities section for clarity and for consistency to the extent possible with the other draft standards in the Generation Verification effort.

As a reminder, the SDT, in its response to industry comments, points out this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.

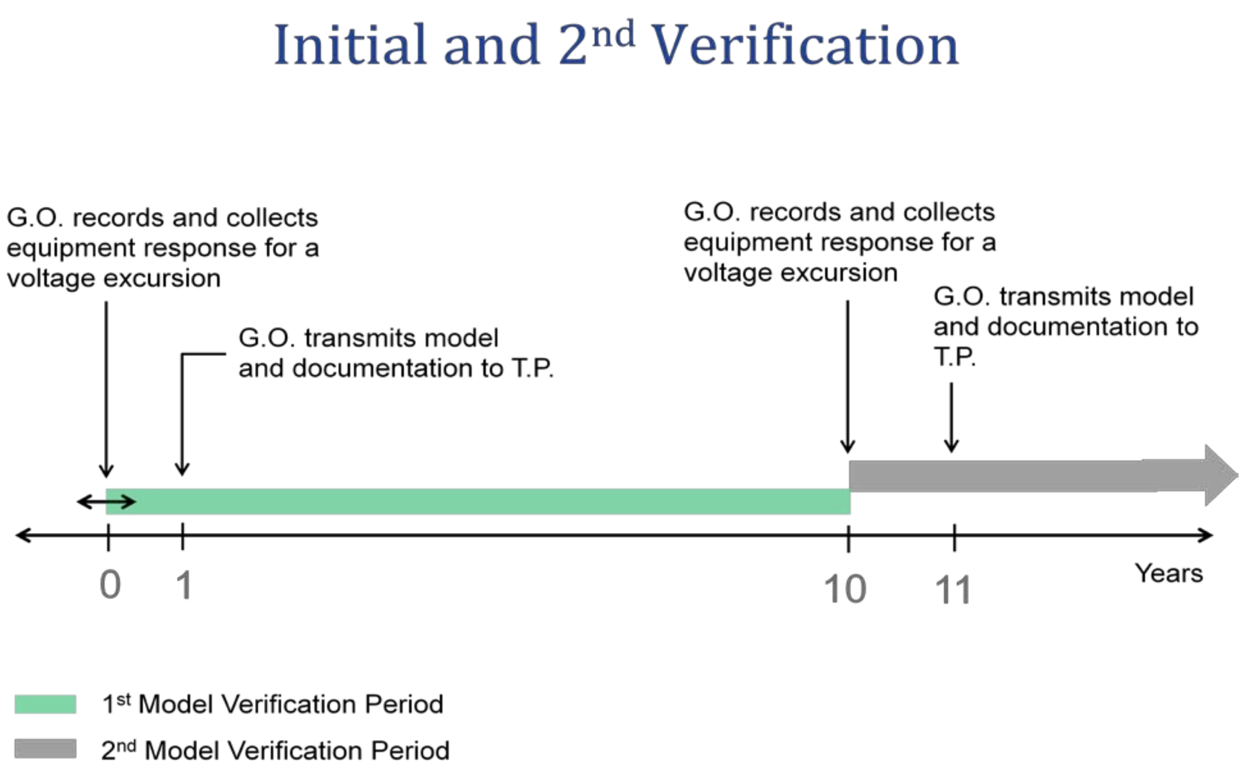
Periodicity Table (Attachment 1) for MOD-026-1:

Based on industry comments from the last posting, the SDT modified the Periodicity Table (Attachment 1) in an effort to convey the required periodicity of model verification in a simple but complete format.

The following examples are offered by the SDT to aid industry in understanding the proposed model verification periodicity:

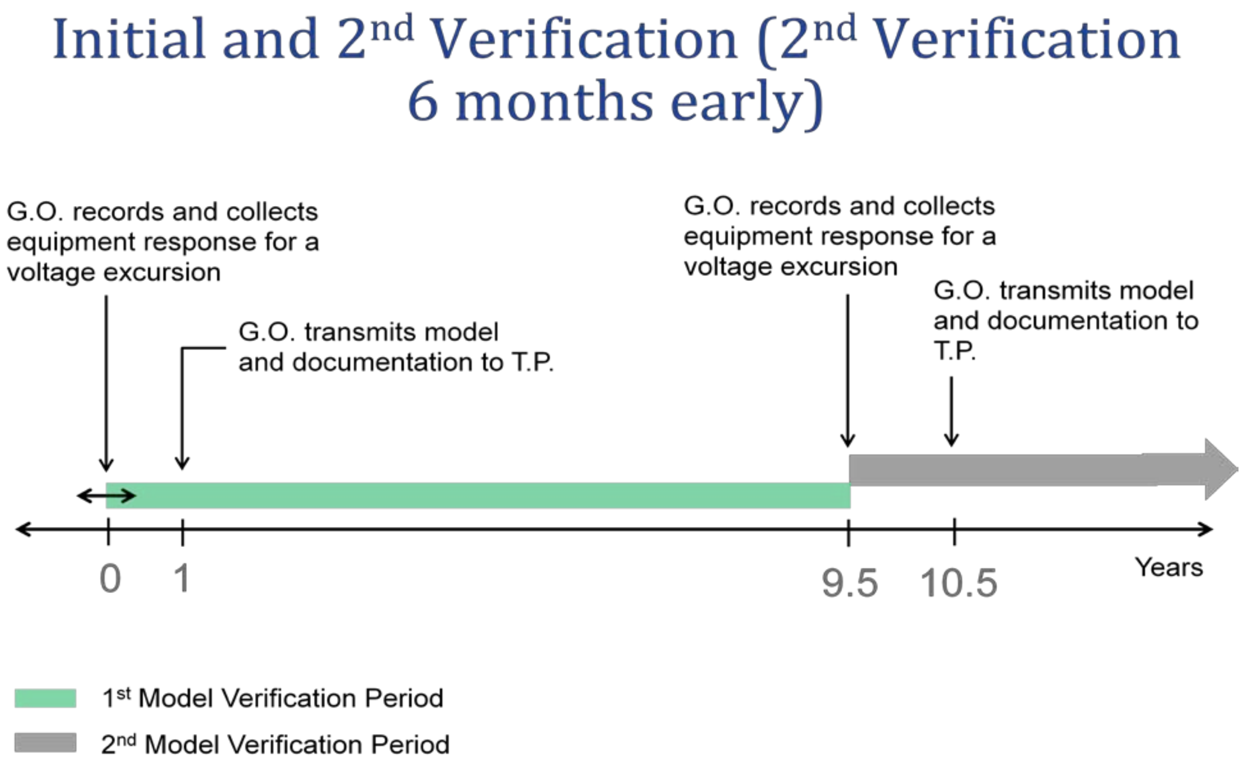
Periodicity Example 1:

The following timeline depicts a model which is initially verified, and then is verified again after a 10-year period. The requirements detailing activities by exception do not occur (R3 – R5) – which is expected to be the situation for the majority of the time. Regarding the third verification (which is not shown on the example below), the GO would need to record and collect equipment response for a voltage excursion on or before the unit's 10-year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation (i.e., response has to be collected on or before Year 20), and transmit the model and documentation to the Transmission Planner no later than 365 days later (i.e., by Year 21):



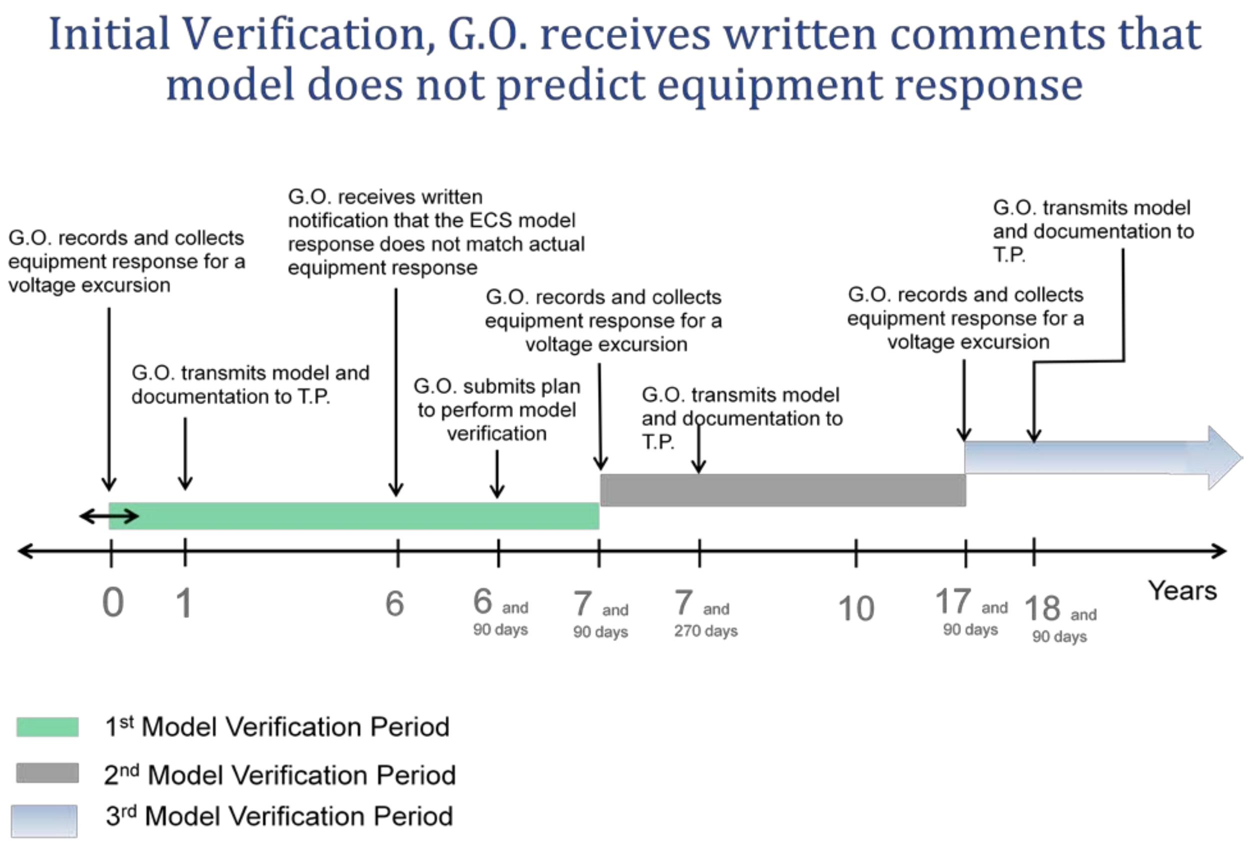
Periodicity Example #2:

The second example is much like Example #1. The only difference is that for the second verification, the equipment response for a voltage excursion was collected on the unit's 9.5 year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation. Regarding the third verification (which is not shown on the example below), the GO would need to record and collect equipment response for a voltage excursion on or before the unit's 10-year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation (i.e., response has to be collected on or before Year 19.5), and transmit the model and documentation to the Transmission Planner no later than 365 days later (i.e., by Year 20.5).



Periodicity Example #3:

The third example details a scenario which the SDT anticipates would rarely occur. Specifically, the scenario assumes that at sometime after the initial verification, the Generator Owner receives written notification that there is evidence that the model does not accurately predict the actual response of the equipment. As detailed in Requirement 3, the Generator Owner has 90 days to respond to the notice. The Generator Owner may respond that the model is still appropriate, or submit model changes – or it may submit a plan to re-verify the model. The example below assumes that later – i.e., the Generator Owner submits a plan to re-verify the model on the 90th day. From that point, per the Periodicity Table, the Generator Owner has 365 days to record and collect equipment response for a voltage excursion and then an additional 180 days to transmit the model and documentation to the Transmission Planner. Regarding the third verification, the GO would need to record and collect equipment response for a voltage excursion on or before the unit's 10-year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation (i.e., response has to be collected on or before Year 17 and 90 days) – and transmit the model and documentation to the Transmission Planner no later than 365 days later (i.e., by Year 18 and 90 days).



PCR-024-1

The GVSDT proposed two new definitions for Voltage Excursion and Frequency Excursion. A slight majority agreed with the proposed definitions. The majority of "No" votes disagreed with the voltage excursion portion of the question, while there was only one vote disagreeing with the frequency excursion portion. After reviewing all comments the SDT made the following changes:

1. The two new terms proposed in the standard were removed. The voltage and frequency excursion values are now located in the requirements where they apply.
2. Attachment 1 (Off Nominal Frequency Capability Curve) was revised to clarify the "no trip" zone.
3. Attachment 2 (Voltage Ride-Through Time Duration Curves) has been clarified. The per-unit-voltage-base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at

the point of interconnection to the Bulk Electric System (BES). In addition, the definition was modified to include the phrase, "Voltages in the curve assume minimum phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum phase-to-ground or phase-to-phase voltage for the high voltage duration curve."

The GVSDT proposed Requirements R1 and R2 to detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Stakeholders were asked if they believed that the draft of these two requirements, including Footnote 1, clarified that a Generator Owner is not required to have protective relaying installed or set for these functions. Stakeholders generally agreed that Footnote 1 does clearly state that a Generator Owner is not required to have protective relaying installed or set for frequency or voltage protection. Many of the stakeholders made additional comments beyond the scope of the question regarding the intention of Requirements R1, R2, and R3 and provided clarifying language examples. In response, the SDT made the following changes:

1. The Requirement Parts were removed from Requirement R1. Part 1.5 is now Part 1.1. The requirement now reads:

"R1. Each Generator Owner that has generator frequency protective relaying1 activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not trip within the "no trip zone" of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
1.1. A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec.
1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

2. Requirement Part 2.1.1 was removed from Requirement R2. The body of the requirement and the remaining parts were modified to clarify intent. The requirement now reads:

"R2. Each Generator Owner that has generator voltage protective relaying1 activated to trip its new or existing generating unit or generating plant shall set its protective relaying such that it does not trip

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

as a result of a voltage excursion (at the point of Interconnection) that remains within the “no trip zone” of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit2 or generating plant [Violation Risk Factor: High] [Time Horizon: Long-term Planning].

2.1. When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. If a Transmission Planner’s study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner’s voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.

2.1.2. Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the “no trip zone” of PRC-024 Attachment 2.

2.1.3. If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the “no trip zone” specified in PRC-024 Attachment 2.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.”

3. Requirement R3 was changed to clarify the intent of non-protection system limitations and when such limitations must be addressed. The requirement now reads:

“R3. Each Generator Owner of an existing generating unit or generating plant shall document each equipment limitation (excluding generator frequency and voltage protective relay limitations) that prevents a generating unit or generating plant, from meeting the criteria in Requirements R1 or R2 including study results, experience from an actual event, or manufacturer’s advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.
- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).”

During the Quality Review process prior to the previous posting, a new Requirement R4 was added based on the comments of the reviewers. This resulted in requirement numbers being incorrect for Questions 3 and 4. The GVSDT will ask these two questions again on the upcoming comment form for the successive ballot. A summary of the comments received is in the following paragraphs.

Relating to question 3 of the previous posting: The GVSDT added Requirement R5 to allow owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information was intended to provide Transmission Planners with information useful in performing planning studies. In the comment form, the question erroneously asked about R4, rather than R5. A few commenters made comments regarding R4, while the vast majority commented related to R5.

Several commenters felt that there is no additional reliability gain in Requirement R5. Their comments indicated that the information is not useful and that there is little technical value in this information. A few commenters expressed the opinion that it is very difficult, if not impossible, to predict the consistent response of the balance of (a generating) plant to the system excursions shown in Attachment 1 & 2. Further, several commenters expressed the opinion that it is unlikely that any steam plant will survive for the entire “no trip zones” of the attachments. Other less frequent comments included the following:

- R1-R4 adequately fulfill the purpose of the standard.
- Standard requirements should be limited to devices that directly respond to the Generator V and F – write standard to exclude all aux system equipment.
- The TP needs only to know when the protective relaying V-t and F-t will trip the unit so the models can switch the generators off when the simulated V and F levels are reached.
- 30 days is too short for a response.

Based on comments received, the GVSDT revised R5 (which is now R4) to:

“R4. Each Generator Owner of an existing generating unit or generating plant shall provide an estimate of that unit’s performance during Frequency/Voltage Excursions to each requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operato,r or Transmission Planner that monitors or models the associated generating unit or generating plant) within 60 calendar days of receipt of a written request to ensure the accuracy of planning studies and system modeling studies. The estimate shall include: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning].
4.1. An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of Interconnection described by dynamic simulation provided by the Transmission Planner. If the

Generator Owner expects the existing unit or generating plant will remain connected for longer than 10 minutes, the estimate should indicate the existing unit or generating plant is not expected to trip.
4.2. Identification of the basis for the estimates developed for 4.1 which may include, but is not limited to: experience, actual event histories, or sound engineering judgment."

Relating to Question 4 of the previous posting: The question mistakenly referred to Requirement R5 due to changes to the standard made in response to the Quality Review. This error was observed by the stakeholders and the SDT believes the responses accurately reflect the feelings of industry to the intended question. The slight majority of stakeholders agree with the requirement, while some stakeholders indicated that they do not feel the requirement is technically achievable. Based on the comments received, no major changes were made to Requirement R6 (now R5).

The GVSDT proposed voltage ride-through tables for High Voltage Ride Through (HVRT) and Low Voltage Ride Through (LVRT) time durations in Attachment 2. These tables specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Stakeholders were asked if they agree with the proposed times in the tables. A majority of stakeholders agreed with the time values. Many of those that responded in the negative to the question indicated that they felt the 600 seconds duration was acceptable but had other concerns with the standard. No substantive suggestions were made for revising R6. As a result, the GVSDT did not make any changes to Attachment 2.

You do not have to answer all questions. Enter All Comments in Simple Text Format.
Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

Questions 1- 5 pertain to MOD-026-1 and Questions 6-8 pertain to PRC-024-1.

Questions

1. The GVSDT has added an additional condition to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed-loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service. Do you agree with this concept? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

2. The GVSDT has provided guidance on the periodicity aspects of Attachment 1 (see above). Do you agree? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

3. Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. Though not a change from the previous posting, the SDT emphasizes for clarity that only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) or units that are already registered (for reasons such as being required to by their RRO) are subject to Requirement R5. Do you agree with the revisions to applicability and to Requirement R5? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

4. To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions. Do you agree with this revisions? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

5. Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-026-1?

Comments:

6. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language.

☐ Yes

☐ No

Comments:

7. Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. Please provide along with your comment, what you believe the timeframe is needed to implement this requirement.

☐ Yes

☐ No

Comments:

8. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-024-1?

Comments:

NERC
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RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-026-1 — Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-026-1:

There are six requirements in MOD-026-1. Four requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-026-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R6; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This requirement is administrative in nature for providing instructions and data used for performing model verification. The “Lower” VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The “Medium” VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to provide a written response after receiving a request. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R5 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 high risk objective is to verify if the model is useable or not.

Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The “Medium” VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-026-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-026-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is timely. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness with completeness of information required for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R5:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating equal multiple parts criteria VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts also incorporate increments for tardiness consideration. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s are a combination of completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 states "… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "	FERC Order 693	The GVSDT believes that Requirement R2 and the voltage ride through curves in PRC-024 Attachment 2 accomplish this. While the curves were developed based on three phase normally cleared faults located at a generating plant substation (the most severe condition for generating equipment), the curves cover voltages depressed as low as 0.65 per unit for two seconds, which the GVSDT feels will cover the Category B and C events of concern to the Commission. Requirement R5 directs all new generating facilities following approval of this standard to be designed, built and maintained so that they are able to ride through the excursions defined in the standard. For existing units, Requirement R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented technical reasons, but directs those generators to communicate that limitation to the RC, PC, TOP and TP so its performance can be modeled correctly. In addition, Requirement R4 allows the RC, PC, TOP, or TP to request an estimate of performance (ride through duration) from the GO for a defined excursion. The estimate would cover process upsets to the generating equipment that might result in a delayed trip, even if the

Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		generator protection itself did not cause a trip.
Paragraph 1787 also states "… the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented technical limitations. The GVSDT believes that NRC requirements qualify as technical limitations for the purposes of this standard.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Performance During Frequency and Voltage Excursions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:
There are six requirements in PRC-024-1. Three of the Requirements (R1, R2, and R5) were assigned a "High" VRF and the remaining three requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2; which remaining standard requirements rationally relate by defining documentation, estimation, expectations during external events, and response expectations.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. In addition, and as is generally the case with PRC standard VRF definitions, this requirement is assigned a "High" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated

by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Therefore the assigned "High" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "High" VRF assigned is based on the high risk objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1; which remaining standard requirements rationally relate by defining documentation, estimation, expectations during external events, and response expectations.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. In addition, and as is generally the case with PRC standard VRF definitions, this requirement is assigned a "High" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Therefore the assigned "High" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "High" VRF assigned is based on the high risk objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 contains Parts that are procedural in nature defining criteria associated with the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires an estimate of performance and is somewhat similar in concept with both PRC-009-0 Requirement R1 and PRC-014-0 Requirement R2, both of which reference protection analysis or assessment for determining adequacy. In addition, as is generally the case with reliability standard VRF definitions for analysis & assessment planning type requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to estimate performance during a frequency or voltage excursion is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the

emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to estimate performance during a frequency or voltage excursion. Requirement Parts and obligations are lower risk procedure based criteria for the main requirement. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for PRC-024-1, Requirements R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying conditions and exceptions for satisfying the main requirement during external events. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires generation to remain connected during external events and as such does not have strong correlation to similar reliability goals listed in different reliability standards. A good approximation in regards to maintaining stable and continuous power operations can be found in standards BAL-002-0 and EOP-008-0; both of which possess a High VRF. Therefore this requirement is assigned a "High" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to remain connected during an external event is a requirement during real-time operation that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures Therefore the assigned "High" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to remain connected during an external event. Requirement Parts specify conditions and exceptions elements that establish main requirement criteria for completeness. The "High" VRF assigned is based on the high risk objective specified.

VRF for PRC-024-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 high risk objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The "Lower" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:
In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness. The Requirement Parts incorporate procedure based criteria elements incorporated as equal multiple parts rationale for completeness of the main Requirement. Requirement Parts are conditions that, if not performed, represent noncompliance of increasing severity based on the number of conditions not observed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements with additional consideration for completeness of listed parts and also increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner per the procedure criteria specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements. Requirement Parts merely identify conditions and exceptions for determining binary VSL status.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate binary methodology. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions and exceptions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Standards Announcement

Project 2007-09 Generator Verification

Ballot Pool Windows Open – Three Ballots and Three Non-binding Polls: Feb. 29 – Mar. 29, 2012

Two Formal Comment Periods Open:

MOD-026-1 & PRC-024-1 Feb. 29 – Mar. 29, 2012

PRC-019-1, MOD-025-2, & MOD-027-1 – Feb. 29 – Apr. 16, 2012

Ballot Windows Open – Two Ballots and Two Non-binding Polls:

(MOD-026-1 & PRC-024-1) March 19 – March 29, 2012

Ballot Windows Open – Three Ballots and Three Non-binding Polls:

PRC-019-1, MOD-025-2, & MOD-027-1) April 6 – April 16, 2012

Now available

The Generator Verification standard drafting team has posted five standards and their associated implementation plans for a formal comment period. Please read the following announcement carefully because, although the five standards are being posted together, they are at different stages in the standards process. In order to facilitate moving forward those standards that reach consensus, the standards are being balloted independently.

MOD-026-1 and PRC-024-1 Formal 30-day Comment Period, Successive Ballot and Non-binding Poll

Two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation Control System Functions , and PRC-024-1– Generator Performance During Frequency and Voltage Excursions, are posted for a 30-day formal comment period through March 29, 2012. A successive ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-026-1 and PRC-024-1 from March 19 through March 29, 2012. Please note that **separate ballot pools were formed for each standard and non-binding poll**.

Instructions for Commenting

Please use this electronic form to submit comments on MOD-026-1 and PRC-024-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit multiple separate sets of comments (one during the comment period and one with each ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

MOD-025-2, MOD-027-1, and PRC-019-1 Formal 45-day Comment Period and Ballot Pool Formation

Three additional standards have been posted for a 45-day formal comment period:

- MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability
- MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- PRC-019-1 – Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

An initial ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-025-1, MOD-027-1 and PRC-019-1 from April 6 through April 16, 2012. Please note that **separate ballot pools are being formed for each standard and non-binding poll**.

Ballot Pools Open through 8 a.m. EST on March 29, 2012 for MOD-025-2, MOD-027-1, and PRC-019-1 Ballots and Non-binding Polls

The Standards Committee has authorized posting these standards and their associated implementation plans for a 45-day formal comment period, with an initial ballot and concurrent non-binding poll conducted during the last 10 days of that comment period. A separate ballot pool is being formed for each standard and for each non-binding poll in order to allow NERC Registered Ballot Body members to selectively join those ballot pools in which they have an interest. To submit an opinion in a non-binding poll for any standard, you must join the ballot poll for that non-binding poll. Each of the six ballot pools will be open through 8 a.m. EST on March 29, 2012.

Instructions for Joining Ballot Pools for MOD-025-2, MOD-027-1, and PRC-019-1 Ballots and Non-binding Polls

NERC Registered Ballot Body members must join each of the ballot pools to be eligible to vote in the upcoming ballots and non-binding polls. Join

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

MOD-025-2 ballot	bp-2007-09_MOD-025-2_in@nerc.com
MOD-027-1 ballot	bp-2007-09_MOD-027-1_in@nerc.com
PRC-019-1 ballot	bp-2007-09_PRC-019-1_in@nerc.com

Instructions for Commenting

Please use this electronic form to submit comments on MOD-025-2, MOD-027-1, and PRC-019-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit multiple separate sets of comments (one during the comment period and one with each ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

Next Steps

Successive ballots of MOD-026-1 and PRC-024-1and concurrent non-binding polls of the associated VRFs and VSLs will begin on March 19, 2012 and end at 8 p.m. Eastern on March 29, 2012. Initial ballots of MOD-025-2, MOD-027-1 and PRC-019-1 and concurrent non-binding polls of the associated VRFs and VSLs will begin on Friday, April 6, 2012 and end at 8 p.m. Eastern on Monday, April 16, 2012. Following the formal comments periods for MOD-026-1, PRC-024-1, MOD-025-2, MOD-027-1, and PRC-019-1, the drafting team will consider all comments and determine whether to make changes to the standards, implementation plans, or associated VRFs and VSLs.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
  MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project web page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 – Generator Verification

Successive Ballot Results – Updated 4/1/2012

Now Available

Ballots of two Generator Verification standards concluded Thursday, March 29, 2012:

- MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions and Plant Volt/Var Control Functions

- PRC-024-1 – Generator Performance During Frequency and Voltage Excursions

Voting statistics for each ballot are listed below, and the Ballots Results page provides a link to the detailed results.

Standard	Quorum	Approval
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions and Plant Volt/Var Control Functions	Quorum: 81.45%	Approval: 61.21%
PRC-024-1 – Generator Performance During Frequency and Voltage Excursions	Quorum: 80.38%	Approval: 41.09%

Next Steps

The drafting team will consider all comments submitted and make revisions to the standards and other documents to respond to the comments. If the drafting team makes substantive revisions, the drafting team will submit the revised standards along with its consideration of comments received for a quality review prior to posting for a parallel formal 30-day comment period and successive ballot.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid-2006 through mid-2007:

- PRC-019-1 — Coordination of Generating Unit or Plant Capabilities , Voltage Regulating Controls, and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project web page at: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

Standards Development Process

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For more information or assistance, please contact Monica Benson,
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Standards Announcement

Project 2007-09 – Generator Verification

Successive Ballot Results

Now Available

Ballots of two Generator Verification standards concluded Thursday, March 29, 2012:

- MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions and Plant Volt/Var Control Functions
- PRC-024-1 – Generator Performance During Frequency and Voltage Excursions

Voting statistics for each ballot are listed below, and the Ballots Results page provides a link to the detailed results.

Standard	Quorum	Approval
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions and Plant Volt/Var Control Functions	Quorum: 80.82%	Approval: 61.25%
PRC-024-1 – Generator Performance During Frequency and Voltage Excursions	Quorum: 79.75%	Approval: 40.99%

Next Steps

The drafting team will consider all comments submitted and make revisions to the standards and other documents to respond to the comments. If the drafting team makes substantive revisions, the drafting team will submit the revised standards along with its consideration of comments received for a quality review prior to posting for a parallel formal 30-day comment period and successive ballot.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid-2006 through mid-2007:

- PRC-019-1 — Coordination of Generating Unit or Plant Capabilities , Voltage Regulating Controls, and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project web page at: http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html.

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Ballot Results	
Ballot Name:	Project 2007-09 MOD-026-1 Successive Ballot March 2012_in
Ballot Period:	3/19/2012 - 3/29/2012
Ballot Type:	Initial
Total # Votes:	259
Total Ballot Pool:	318
Quorum:	**81.45 % The Quorum has been reached**
Weighted Segment Vote:	61.21 %
Ballot Results:	**The drafting team is considering comments.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	85	1	41	0.621	25	0.379	5	14
2 - Segment 2.	6	0.3	1	0.1	2	0.2	1	2
3 - Segment 3.	68	1	31	0.574	23	0.426	2	12
4 - Segment 4.	25	1	9	0.45	11	0.55	2	3
5 - Segment 5.	75	1	33	0.611	21	0.389	4	17
6 - Segment 6.	42	1	20	0.645	11	0.355	2	9
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	5	0.5	1	0.1	0	2
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.6	4	0.4	2	0.2	1	0
Totals	**318**	**6.7**	**146**	**4.101**	**96**	**2.599**	**17**	**59**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Abstain	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Negative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	View
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Orlando Utilities Commission	Brad Chase		
1	PacifiCorp	Colt Norrish	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	View
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		

1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson		

3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	View
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	View
4	Imperial Irrigation District	Diana U Torres	Affirmative	View
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Negative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	

5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	View
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	View
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	

6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	View
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	View
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	View
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Brendan Kirby	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton		
8		Edward C Stein		
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley	Negative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2007-09 PRC-024-1 Successive Ballot March 2012_in
Ballot Period:	3/19/2012 - 3/29/2012
Ballot Type:	Initial
Total # Votes:	254
Total Ballot Pool:	316
Quorum:	80.38 % The Quorum has been reached
Weighted Segment Vote:	41.09 %
Ballot Results:	The drafting team is considering comments.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	82	1	25	0.391	39	0.609	4	14
2 - Segment 2.	6	0.4	2	0.2	2	0.2	0	2
3 - Segment 3.	68	1	17	0.309	38	0.691	0	13
4 - Segment 4.	25	1	5	0.25	15	0.75	2	3
5 - Segment 5.	76	1	15	0.283	38	0.717	3	20
6 - Segment 6.	42	1	10	0.303	23	0.697	1	8
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	5	0.5	1	0.1	0	2
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.7	4	0.4	3	0.3	0	0
Totals	**316**	**6.9**	**85**	**2.836**	**159**	**4.064**	**10**	**62**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott J Kinney	Negative	View
1	Balancing Authority of Northern California	Kevin Smith	Negative	View
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Abstain	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Negative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Orlando Utilities Commission	Brad Chase		
1	PacifiCorp	Colt Norrish	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	View
1	Potomac Electric Power Co.	David Thorne	Negative	View
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Negative	View
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	View
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Ocala Electric Utility	David Anderson		
3	Orlando Utilities Commission	Ballard K Mutters	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	View

3	PacifiCorp	John Apperson	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	View
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	View
4	Imperial Irrigation District	Diana U Torres	Affirmative	View
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Negative	View
5	Chelan County Public Utility District #1	John Yale	Negative	View
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	View
5	City of Redding	Paul Cummings	Negative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Cowlitz County PUD	Bob Essex		

5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh		
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff		
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	View
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Negative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	View
6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		

6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Negative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	View
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	View
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton		
8		Brendan Kirby	Affirmative	
8		James A Maenner	Affirmative	
8		Edward C Stein		
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley	Negative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	View

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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Name (34 Responses)
Organization (34 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
Question 1 (39 Responses)
Question 1 Comments (53 Responses)
Question 2 (38 Responses)
Question 2 Comments (53 Responses)
Question 3 (40 Responses)
Question 3 Comments (53 Responses)
Question 4 (38 Responses)
Question 4 Comments (53 Responses)
Question 5 (0 Responses)
Question 5 Comments (53 Responses)
Question 6 (41 Responses)
Question 6 Comments (53 Responses)
Question 7 (35 Responses)
Question 7 Comments (53 Responses)
Question 8 (0 Responses)
Question 8 Comments (53 Responses)

Individual
Frederick R Plett
Massachusetts Attorney General
No
a particular unit may not pose much problem to a system but an aggregation may. One would think that over a threshold # of MW that active close loop regulation functions should be present.
Yes
No
I am concerned about units that may be individually less than 20 MVA but collectively could eb much larger - wind farms.
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
No
While some plants may not have excitation systems, they can have complex reactive coordination controllers whose settings and functions should be tested and verified.
Yes
No
Footnote 4 in the Applicability Section implies comparing simulated unit or plant responses to dynamic system events. Verifying the model only after an event as is called for in footnote 4 is completely counter to increasing system reliability. Analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. The Applicability Section needs

further revision because by requiring only generators above 100 MVA with unit capacity factors above 5 % to test excludes an unacceptably large amount of installed generation. For example, about 30% of the installed generation in New England would not therefore, require model validation. This is an excessively large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being most stressed and reliable operation is being most challenged. If the objective of the Standard is to develop the right models for dynamic suimualtions, models must include high and low capacity factor units, transient and long term models, etc. for all network conditions. A model for the generators and associated equipment is supplied in accordance with MOD-012. The accuracy of such models may be limited and a higher percentage of generator validation is required. Footnote 4 should be changed to allow verification of generator models not required under the Applicability Section to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical. Requirement R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate. What is meant by a “technically justified request” from the PC? R5 refers to the Planning coordinator, yet the Planning Coordinator is not listed in the Applicability Section of MOD-026. MOD-026 deviates from the NERC Functional Model Version 5 in that MOD-026 R5 has the Generator Owner communicating with the Planning Coordinator. The NERC Functional Model stipulates that the Transmission Planner communicates with the GO/GOP. The PC then collects the data from the TPs in its area, and from adjacent PCs. The Standard should be consistent with the NERC Functional Model.
Yes
While supporting the clarification of capacity factor concerns, there is concern with the exclusion for units with less than a five percent capacity factor. See comments provided to Question 3. Average Capacity Factor should be defined.
Use of the terms Bulk Electric System (BES) in the Purpose and bulk power system in the Facilities Section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). In the Applicability Section under the Introduction, the bullets under 4.2.1.2 are unnecessary. The wording of 4.2.1.2 already covers what the bullets detail. Regarding Requirement 2: • R2.1.1: requires that model results must “match” results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be a stipulated allowable tolerance band. Suggest that a tolerance be a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the bus voltage being controlled. • R2.1.1: A unit’s “point of interconnection” is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term “point of interconnection” may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the bus controlled by the generator excitation system. Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. Why are the References listed in Section G included? They are described as being “beyond the scope of this Standard”. The language for R4 should be reworded as follows: “R4. Each Generator Owner shall provide revised model data or plans to perform model verification7 (in accordance with Requirement R2) to its Transmission Planner within 180 calendar days of prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response8 characteristic.” The way the language is currently written, the generator has to provide its revised model data or plans to perform model verification within 180 days of making the change. For up to 180 days after a change has been made the correct data still may not have been made available to the Transmission Planner. This could have a significant impact on reliability. The suggested rewording addresses this possibility. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs. What is the definition of Gross Nameplate Rating as used in the Standard?
Yes
No
The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard allows loopholes which undermine reliability.

Suggest revising Requirement 5.6 from “may retroactively grant a temporary exemption” to “may grant a retroactive temporary exemption”. The magnitude of voltage excursions at the point of interconnection may be different from the generator terminals where generator relays receive their voltage inputs.
The definitions of the terms Frequency Excursion and Voltage Excursion were deleted. All references to these terms should be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use the lower case terms. Regarding requirement R2, the time duration is acceptable. However, the band is shown as 0.95 per unit to 1.05 per unit at the point of interconnection, and there are areas of the power system that have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 per unit to 1.05 per unit. Failure to make this change means that it would be acceptable for generators to trip during steady state operation of the system on “low” voltage. Unanticipated and unncecessary tripping of generators under steady state conditions could lead to significant reliability concerns on the system. The PTs connected to the high voltage terminals of the GSU may not be used as a source for generator protective relaying. Generator protective relays may be connected to the generator output terminals for their source of potential. The wording of R2 should incorporate generator terminals in addition to point of interconnection. Regarding R3, in the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the “No Trip Zone”, there is no requirement to correct the issue. The generator must only document the limitation. This completely undermines the intent of this standard. It is counterproductive to set undervoltage relays to meet the curve if other equipment is still going to trip the plant for those same conditions. This standard appears to simply document system concerns rather than identify and correct them. Under Requirement R5, 5.5 (exception) is unnecessary. It does not have to be stated that a generating unit or generating plant may trip if clearing a system fault necessitates disconnecting the generating unit or generating plant.
Group
Luminant Power
David Youngblood
Yes
Yes
Yes
No
Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross and Net). The standard should specify Net Capacity Factor.
No
An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
No
Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The “maintain” requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.

1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the “no trip zone” of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become “Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds.” For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; “ … unless the generator owner has identified an equipment limitation …” 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. 4. Overall, this standard should address voltage and frequency relay settings only.
Group
Progress Energy
Jim Eckelkamp
Our AFFIRMATIVE vote is conditional upon the "Clean" version being voted on. There are major differences between the Red-line and clean version in Section 5 "Effective Date". The Clean version 5.1.3 requires 50 % where as Red-line version has 100 %
No
Progress Energy has a concern associated with the voltage ride through curve referenced in R5 (Attachment 2). The concern is not about setting the relay protection to ride through this transient or the generators capability of riding through such a transient but of the physical capability associated with the large pumps and motors in the auxiliary equipment that would be subjected to this transient. A lot has to do with the size of the motors at the 4160 or 6900 volt level and the control relays at the 480 volt level. After 9 cycles at zero voltage the phase of the motor decay voltage and the incoming line voltage of the large motors may have shifted significantly causing large currents to be drawn when the voltage is restored to the motor. This could cause significant cyclical torques on motor shafts that can damage the shaft over time. Also the control contactors for most 480 volt control circuits do not hold in for less than 60 -70 % voltage. The capability of UPS systems are not sufficient to power the large motors being discussed and it may not be feasible to UPS all the plant 480 volt control circuitry. (We wouldn’t be concerned with 480 if we thought we would lose higher voltage equip…) To implement this requirement as presently worded appears to be impractical and could prevent building of any new generating facilities at reasonable cost. There needs to be some ability to deviate for the specific requirements of the voltage curve in Attachment 2 if it can be show that the fault clearing time for the bulk electric system that the unit is connected to is different than the specific voltage requirements of Attachment 2 or there needs to be some more specific wording excluding the auxiliary equipment from the requirements of this voltage curve.
Individual
Dan Roethemeyer
Dynegy
Yes
Yes

Yes
Yes
The division of responsibility (between GO and TP) in the task of ‘verifying’ the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and ‘verify’ the models. This would also eliminate the question of what constitutes a ‘verified’ model, i.e., how good is good enough.
Yes
Yes
No
Group
Texas Reliability Entity
Don Jones
Yes
Yes
Yes
(a) R5 should be limited to generating units and plants that meet the Registry Criteria. For clarity, we suggest rewording R5 with “…perform a model review of any generation unit or plant meeting the Registry Criteria, but not included as an applicable unit in Section 4.2, that includes one of the following…”. (b) Does similar language (i.e. section 4.2.4) need to be added to MOD-027-1?
No
We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an “applicable unit”.
1) Applicability: The applicable Facility requirements should be the same for every Standard in this Project! 2) Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection. 3) Effective Dates: Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correcting model errors that may lead to (or have led to) improper planning of the system based on the current model results. 4) The SDT should consider moving the “Consideration for Early Compliance” criteria from Attachment 1 into the Effective Dates section. 5) Regarding Requirements R3 and R4: The inclusion of “or a plan” extends the timeframe associated with getting good modeling data to the TP. What does the Transmission Planner do in the interim? Who is responsible for the use of the unusable or invalid data? Does the unusable or invalid data get used at all (do the plants need to disconnect until “usable” data is provided)? 6) Regarding VSLs for R1, R3, R4, R5 and R6: The numbers of days stated in the Severe VSLs need to be reconsidered. For example, in the Severe VSL for R1, no VSL applies if the performance occurs on day 181. 7) Regarding VSL R5: There is reference to Subpart(s) 5.2 and 5.3 in the High and Severe VSL text, but there are no corresponding subparts in the Standard. 8) Regarding Attachment 1: The allowed time to provide usable verified models is far too long. For example, as written there could be a gap of almost two years between the time a TP learns that a model is “unusable” and the time the GO has to provide a verified model. 9) In

Attachment 1, change “356 days” to “365 calendar days” in the third line of the table for consistency.
No
Most existing facilities are likely not designed to a frequency or voltage ride-through standard, and a useful estimate may be very difficult for owners to provide. Generator Operators may be able to document “known” equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation.
No
While it is technically feasible to set generator protective relays to meet the intent of this Standard, there are technical limitations that may prevent manufacturers from achieving it, especially if the term “generating plant” includes auxiliary equipment within the plant that is required for the generator to continue to operate. The standard needs to clarify if and how the limitations of auxiliary equipment are to be addressed in connection with applicable generating facilities.
1) Purpose Statement: If we correctly understand the intent, the second comma should be removed. 2) Does the SDT want to consider any specific requirements regarding generators that are connected as synchronous condensers, and is it the intent of the standard to cover this operating mode? 3) All requirements: Need to clarify the phrase “generating unit or generating plant”. Does the “generating plant” phrase imply that the frequency and voltage setting criteria also applies to plant auxiliary equipment (referenced in R4)? In ERCOT, we have seen multiple instances where close-in faults have created low voltage conditions which caused auxiliary equipment to trip (boiler feed pumps, baghouse fans, etc.) which in turn caused a unit runback and trip. If the intent of this standard is to also cover plant auxiliary equipment, then this needs to be very clearly stated in the Applicability section and/or in the Requirements. 4) R1 and R2: The SDT may want to consider adding Volts per Hertz criteria. For example: ERCOT region criteria currently states a generator must remain connected if Volts/Hertz is less than 105% of generator design voltage and frequency, and also if Volts/Hertz is less than 116% of generator design voltage and frequency for less than 1.5 seconds. 5) R1: Need to add “or generating plant” to end of R1. 6) R2: Need to specify that the undervoltage “no trip zone” applies to both single-phase and three-phase voltage excursions. 7) R2.1.2 and 2.1.3 need to include the phrase “generating unit or generating plant” versus “generator” to be inclusive of a plant site and provide consistency throughout Standard. 8) R1 and R2 Exclusions: The SDT may want to consider these additional exclusions: a. A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system. b. A generation unit may trip by frequency or voltage protection if the unit is being operated below its Low Sustained Limit (LSL), where LSL is defined as the limit established by the Generator Operator that describes the minimum sustained energy production capability of the generator. c. A generator unit may trip by frequency or voltage protection if the unit is being operated in a “Test” status and is not under AGC control. 9) R3: Generator Operators should be required to document “known” equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation. Also need to clearly state if this requirement (i.e. due to the phrase “generating plant”) also applies to plant auxiliary equipment, which would require the GO to provide extensive review and documentation on all of their plant auxiliary systems as well. 10) R5: Need to clearly state if this requirement applies to plant auxiliary equipment. 11) In 5.2, insert “nameplate” after “aggregate” to be consistent with R5.1.1. 12) R5 Exceptions: The SDT may want to consider these additional exceptions: (a) A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system. (b) A generator unit may trip by frequency or voltage protection if the unit is being operated in a “Test” status and is not under AGC control. 13) In Measures M1 and M2: See comment 3 above regarding the use of the phrase “generating plant”. Is it the intent of these measures to also cover frequency and voltage setting sheets for plant auxiliary equipment protection systems? 14) In Requirement R4, Measures M4 and M5, and some VSLs: Remove capitalization of “Frequency/Voltage Excursions” and similar terms (e.g. Frequency Excursion), which are not formally defined in this standard nor in the NERC glossary. 15) VSLs for R1, R2, and R3: What is the SDT’s intent regarding a GO that has set its relays per R1 and R2, and has no documented equipment limitations per R3, but still experiences a unit trip within the one of the “no trip” zones in Attachment 1? Is that intended to be a violation of this standard? There is not a VSL for this situation. The VSL for R5 contemplates a violation for tripping in the no-trip zone, but it only covers “new” generation units, and there is not a similar VSL

for existing units. 16) VSL for R1 and R2: The term “technical” should be replaced with “equipment” to be consistent with the Requirements. Need to replace “generator” with “generating unit or generating plant” to be consistent with the Requirements. 17) VSL for R2: Language should be similar to VSL for R1 with respect to “activated to trip” phrase and to be consistent with the Requirement itself. Suggest replacing “conditions” with “criteria” to be consistent with VSL for R1. 18) VSL for R3 and R4: What VSL applies if the communication occurs on day 61? It looks like the answer is “none.” 19) VSL for R3: See comment 9 regarding requirement R3 above. The requirement and VSL should only apply to “known” equipment limitations. 20) VSL for R4: Consider changing “unit’s performance” to “unit’s or plant’s performance.” 21) VSL for R6: Remove the phrase “or limitations,” because R3 discusses limitations and the reporting thereof and it is out of place here. 22) Attachment 1- Change “Texas Interconnection” to “ERCOT Interconnection”. 23) Regarding the Voltage Ride-Through Curve Clarifications: The reference to a generation facility’s “point of interconnection to the Bulk Electric System” is incorrect, because the generation facility is itself part of the BES. We assume this is intended to refer to the point of interconnection between the generation facility and the transmission facility, and the text should be modified accordingly.
Individual
Matthew Pacobit
AECI
Yes
Yes
No
I believe that the threshold of 20 MVA is too low. I would recommend a threshold of a (> 75 MVA)
Yes
No
My concern with this requirement is that if a GO provides an estimate of how long they believe that the unit can ride out the event, then what will happen if they do not make this target? Will the GO be held responsible for not making this time? Due to this concern how accurate are these times that are provided by the GO going to be and how much will be a built in cushion?
No
In my opinion, there needs to a definition of what is considered to be a new plant. Many plants are being built that were actually plants and projects that started 10 years ago. I do not believe that those plants should be included.
Individual
John Seelke
PSEG
Yes
Yes
The examples in the unofficial comment form should be incorporated into an attachment to the standard for ease of reference.
Yes
Yes
We have these additional comments: a. The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However,

companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency. b. The entire section 4.2 has language that includes “directly connected to the bulk power system.” The BES is a subset of the BPS (per Order 743), and the GVSDT should consult with the SDT for Project 2010-17 – Definition of BES – to develop alternate language that instead refers to the BES.
Yes
We do not know whether new units installed 6+ years out can meet the requirements. We suggest that the team should reach out to OEMs for their input.
We have these additional comments: a. In Part 4.1 of R4, the first sentence has this proposed change, indicated by capilatization: “An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection [deleted “described by”] THAT WAS DEVELOPED FROM A dynamic simulation provided by the Transmission Planner. b. M5 is confusing. M5 states “Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a Frequency Excursion or Voltage Excursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip.” i. Frequency Excursion and Voltage Excursion are capitalized terms – the previous version’s defined terms were supposed to be removed. ii. While is appears that an “attestation that the generating unit or generating plant did not trip” is only required for a unit or plant that remained on line during a frequency or voltage excursion, the language should be made clearer. iii. We suggest that the GVSDT consider rewording M5 to clearly state what trips should be reported, whether non-trips that occur during frequency and voltage excursions are to be reported, and what supporting evidence (or attestations) is required for each reported item. A table may be the best way to display this. Finally, M5 should be developed to produce the VSL metric for R5. c. The previously defined terms “Frequency Excursion” and “Voltage Excursion” were to be removed from this draft; however they are used in R4 and in the VSL table. The GVSDT should search the standard for all such usage and correct it.
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
Yes
Yes
Yes
Yes
Yes
Yes
We would suggest revision of M5 to read. Also since the two terms Frequency Excursion and Voltage Excursion are no longer to be defined by this project we would ask that you use the lower case for these terms in the standard. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied.
Individual
Chris de Graffenried

Consolidated Edison Co. of NY, Inc.
No
Requirement 5: • R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate. • It is not clear what constitutes a “technically justified request” from the PC. • Refers to Planning Coordinator, but PC is not listed in Applicability section of MOD-026. • Further, under NERC Functional Model Version 5 the Transmission Planner communicates with the GO/GOP. The PC collects data from the TP’s in its area and from adjacent PC’s. See NERC Functional Model Version 5. The standards should conform to the NERC Functional Model.
Use of terms Bulk Electric System (BES) in the purpose and bulk power system in the Applicability section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). Requirement 2: • R2.1.1: requires that model results must “match” results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be some stipulated allowed tolerance band. We suggest that a tolerance is a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the buss voltage being controlled. • The units “point of interconnection” is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term “point of interconnection” may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the buss controlled by the generator excitation system. The Applicability Section of the Standard, Section 4.2 permits exclusion of generators with a low capacity factor (< 5%). Why should the Standard allow an exemption for low capacity factor units? The objective of the Standard is to develop good excitation models for dynamics simulations, which are often conducted under high load conditions. At higher loads, these lower capacity factor units are frequently needed and operating. Therefore the Standard should apply to even lower capacity factor units. Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. Note, there is an entire page of technical references included in the Standard (section G). It is not clear why this is necessary, as the references are described as “beyond the scope of this Standard”.
Requirement 5.6 suggested wording revieion: Replace “may retroactively grant a temporary exemption” with “may grant a reactoactive temporary exemption”
The definition of the terms Frequency Excursion and Voltage Excursion were deleted. All references to these terms should now be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use lower case terms.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
Yes
The examples included in the Unofficial Comment Form are helpful in understanding the periodicity requirements associated with verifying the excitatation and volt/VAr control systems model and should be moved into an attachment in the standard. The standard is not as clear as the examples and the periodicities could be misinterpreted in the future without examples.
No
We appreciate the drafting team explaining their intent that only those units that meet the Compliance Registry Criteria are included. However, the language in the standard does not communicate this and the Statement of Compliance Registry Criteria has some ambiguous criteria that makes it unclear if a generator is applicable which is further discussed below. First, applicability section 4.2.4 of the standard discusses “any registered technically justified unit”. Units are not registered. Entities (i.e. companies) are registered. A Generation Owner certainly becomes registered

by the application of the Compliance Registry Criteria to its generating fleet but there is no publicly available list to which the applicable entities can refer to identify if a generating unit met the Compliance Registry Criteria. Thus, how would a Planning Coordinator know they could make a request? Second, the Compliance Registry Criteria includes units smaller than the 20 MVA unit threshold and 75 MVA plant threshold referenced by the drafting team. Blackstart Resources are included in the Compliance Registery Criteria and there is a statement that any generator that is material to the reliability of the Bulk Power System can be included. Blackstart Resources are usually very small and most likely do not meet the 5% capacity factor requirement established in other areas of the applicability section. We are guessing the drafting team did not intend to include these Blackstart units or any others units that don't meet the 20 MVA unit threshold and 75 MVA plant threshold established in Criteria III(c).1 and III(c).2 with the Appendix 5B – Statement of Compliance Registry Criteria. For clarity, the drafting team should modify applicability section 4.2.4 accordingly to eliminate units that are not intended to be included. Third, we disagree with the statement in the Background Information section of the comment form that the applicability section would have to explicitly identify units below the Compliance Registry Criteria. Because the standards applicability is not specifically limited to the Bulk Electric System, the statement in Requirement R5 that "any/plant not included in the Applicability" means that any unit that is considered part of the Bulk Power System could be requested by the Planning Coordinator. NERC enforces standards to the Bulk Power System which could include units below the Compliance Registry Criteria. They have made this clear in response to comments on CAN-0016 that the standards are enforced to the Bulk Power System. They stated clearly "According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." While the Bulk Power System has never been clearly defined, we know that it is broader than the Bulk Electric System and could certainly include units below the Compliance Registry Criteria. One solution to more fully implement the expressed intent of the drafting team would be to limit the applicability section to the Bulk Electric System. Another would be to modify "any unit/plant not included in the Applicability" in Requirement R5 to "any unit/plant on the Bulk Electric System and not included in the Applicability". While the question posed by the drafting team here indicates that their intent was for the Planning Coordinator's technical justification to indicate that the actual unit response does not match the simulated response, there is nothing in the standard or requirement that indicates this intent. In fact, it only states the request from the Planning Coordinator must be technically justified. We suggest the drafting team modify Requirement R5 to make it clearer the actual system response does not match simulated response.
Yes
We continue to believe that this standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. This is the purpose of the FFT process that NERC initiated and FERC recently approved. Interestingly, within the approval order, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard and the problem with attempting to memorialize the cooperation that must occur between the Generator Owner and Transmission Planner to model the generator's excitation and volt/VAr control functions accurately. Requirement R3 allows a Generator Owner to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems can not be left unsolved. It should be struck. We are not convinced Requirement R4 is needed. The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of

applicable control system changes. For Requirement R5, there is no clarity for how soon the Generator Owner has to address the model concerns communicated by the Planning Coordinator. If the Generator Owner has the unit in its 10 year plan to test their generation fleet's control systems, they could simply communicate that plan which might be much longer than the Planning Coordinator intended. The drafting team needs to provide more guidance on whether the Generation Owner is expected to accelerate their plans for the unit in question by the Planning Coordinator and by how much. For Requirement R5, who decides if the request is technically justified? Could the Generator Owner simply choose not to respond because they do not believe the request is technically justified? In the Background Information section of the comments, the drafting team indicated that the "standard is drafted to provide the proper cost/benefit balance for performing generator verification". Since the summaries of field test results posted with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit and that does not even include opportunity costs from lost energy sales should the test cause the unit to trip, we believe it would be helpful for the drafting team to provide information on the cost/benefit that was discussed in the Background Information section of the comment form in the next posting. The response to our comments regarding consideration for early compliance from the last posting was not satisfactory. In our comments we stated that we appreciated the drafting team's consideration to allow for early compliance based on past tests. However, we stated concerns regarding how to demonstrate this compliance because a registered entity was not required to retain documentation and may not be able to prove they completed a test. The drafting team responded that demonstration of compliance was beyond the scope of the drafting team. While we agree demonstration of compliance for specific companies and situations are likely beyond the scope, demonstration of compliance in general is never beyond the scope. Drafting teams must write standard requirements with which can be complied. Given that the issue of evidence retention from before the effective date of the standard was one of the key subjects in the High-level review conducted by NERC for CAN-0008 recently at the request of the Trade Associations, we suggest the drafting team should consult the appropriate NERC subject matter experts to determine how to avoid these similar issues with this draft standard. Sections 4.2.1.2, 4.2.2.2, and 4.2.3.2 are confusing and potentially contradictory. First, these sections state that they apply to each generating plant/Facility greater than 100, 75 and 50 MVA respectively. Then, the second bullet under each of these sections applies to generating plant/Facility. How can there be a plant within a plant? With the first bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 50 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for individual generating units than section 4.2.1.1, 4.2.2.1, and 4.2.3.1 which apply to individual generating units. For example, 4.2.2.1 applies a 75 MVA threshold to an individual generating unit and then the first bullet of section 4.2.2.2 applies a 20 MVA unit threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. The NERC Glossary of Terms uses a generator as an example of a Facility. In the second bullet under each segment, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. The VRFs simply do not meet the NERC definitions for anything greater than Lower. Requirements R2 and R6 are written with Medium VRFs. All other requirements have Lower VRFs. Neither Requirement R2 nor R6 could be construed as affecting the electrical state or capability of the Bulk Electric System or the ability to monitor, control or restore it. Per NERC definition of Medium VRF, these are prerequisites for meeting a Medium VRF. For Requirement R1, the VRF justification for FERC Guideline 5 refers to the requirement having a high risk objective. This is not consistent with a Lower VRF. We agree with the Lower VRF and recommend removing the "high risk objective" language. All of the measurements use language that sounds like it is creating a new a requirement and is not consistent with language used in any other NERC standard. They all use "must include". It is more typical to use "shall demonstrate", "shall make available", etc. These measurements should be made consistent with other NERC standards. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. Some examples of the proof include dated postal receipts, dated confirmation of facsimile, etc. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. The

Compliance Enforcement Authority section is not the latest approved language being used by NERC. In the data retention section, there is no length of time given for how long a Generation Owner must retain information for Requirement R2 and its associated measurement. The High and Severe VSLs for Requirement R5 need to be updated. They still refer to Subparts 5.2 and 5.3. The Subparts have been changed to a bulleted list which means they are options. Thus, missing one and meeting the other is full compliance and not partial compliance as the VSLs suggest. We suggest the drafting team write a brief paragraph at the beginning of the Reference section to explain the inclusion of the References. Currently, it states that those references contain technical information that is out of scope of the standard. If so, what is the purpose of including them? We are not against including them but just believe a short explanation for their inclusion is necessary. The verification periodicity for row 3 in Attachment 1 needs to be updated from 356 days to 365 days. Furthermore, the drafting team should consider using a year to account for leap years. Otherwise, every four years we are shifting the compliance date up by one calendar day.
No
This requirement will essentially be redundant with standards MOD-026 and MOD-027. MOD-026 already requires the Generator Owner to verify its excitation and volt/VAr control systems. MOD-027 already requires the Generator Owner to verify its frequency response and its turbine/governor, load control and active power/frequency control models.
No
It is not clear to us why this requirement is needed given the many tariffs that already exist to govern interconnection requests. These tariffs already have well established facility connection requirements. If the requirement persists, we believe it actually belongs in the FAC-001 standard which establishes facility connection requirements for new facilities including generators. While we believe that this requirement is probably technically achievable in most cases, there should be exceptions available. It looks like Part 5.3 will allow the Transmission Planner to offer these exceptions. However, this does not consider that the Transmission Planner in many cases (especially organized markets) is not the entity evaluating interconnection requests. Thus, the Planning Coordinator should be allowed to grant exceptions in those situations as well. The need to supply the bases for the estimate in Part 4.2 is not clear, offers no reliability benefit and is administrative in nature. Of the three bases listed, (experience, actual event histories, or sound engineering judgment) what will the RC, PC, TOP, or TP do with the bases? Will they decide the bases are invalid and substitute their own judgment? If so, what is the purpose of getting an estimate from the Generation Owner anyway? It appears to be a documentation requirement that offers no reliability benefit or even information for which the recipient of the information could take action.
Because NERC has made clear that standards are enforced against the BPS and not the BES, the applicability section should be modified to state clearly that it applies to Facilities that are part of the BES. Otherwise small generators that do not affect reliability could be impacted by these standards. NERC enforcement has made this clear in response to comments on CAN-0016 that the CIP-001 standard applied only to the BES. They stated clearly: “According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS.” Use of “new or existing” as a description for the generators in Requirements R1, R2 and R5 is confusing. What exactly constitutes new and why is it relevant? The requirements are performance requirements that apply to in-service generators so how does new help explain this further? The footnote in Requirement R5 only further confuses the situation since it is not included in Requirements R1 and R2. Part of the confusion likely centers around Requirement R5 applying to maintaining new generators frequency and voltage excursion performance as well as designing and building it. If “maintain” was removed from Requirement R5, we believe “new” could be removed from Requirement R1 and R2 and they essentially become the maintenance requirements. Furthermore, “new and existing” is not used consistently within other requirements such as Requirement R4. It is not obvious why it would not apply to Requirement R4 it if applies to Requirements R1 and R2. Neither Requirement R1 nor R2 state within the main body of the requirement that the Parts are intended to be exceptions to the requirement. For clarity, there should be a statement (i.e. except when the Parts 1.1 and 1.2 are met) within the requirement that makes this clear. For Requirements R1 and R2, it is not clear if the sub-parts are the only reasons that allow for exceptions if other equipment limitations exceptions are allowed. Other equipment limitations should be allowed, and these requirements should be clarified to allow them. As written, Requirement R5 appears to be assumed to apply to a new generator in perpetuity. We draw this

conclusion from the inclusion of "maintain" in the requirement. We think it makes more sense to have this requirement apply only to designing and building a new unit and then have the requirements that apply to existing units apply to the maintenance of the new units once they are established. The standard does not appear to allow "new" generating units to have frequency and voltage excursion performance limited by equipment. It should allow "new" equipment as it experiences normal wear and tear as well as damage for any other reasons to document its equipment limited frequency and voltage performance and communicate it similar to Requirements R1 through R3. Otherwise, a Geneator Operator with a "new" generator that has damaged equipment will be forced between operating the unit in a limited manner providing reliability support to the BES and possibly in violation of this standard or taking a forced outage to avoid violating the standard and experiencing escalated penalties for knowingly violating the standard. We do not believe that Reliability Coordinator is the proper entity to grant a temporary exemption in Part 5.6. Rather, it is the Planning Coordinator that should grant the exemption. Furthermore, this is not consistent with other requirements such as Parts 2.1 and 2.1.1 that specify the Transmission Planner grant the exemption. Of course, Part 5.6 would not be necessary if Requirement R5 did not deal with maintaining the unit and allowed the other requirements that apply to existing units to address maintenance. We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary.
Individual
Dale Fredricksen
We Energies
Yes
add more explicit detail to the Table to indicate that the exemption may apply to some wind farms, solar resources, etc.
No
We strongly oppose this Requirement as unnecessary to the reliability of the BES. Requirement R5 should be removed from the draft Standard. Either the standard is applicable to a generating unit, or it is not. A generating unit that is not covered in the Applicability section should be exempt from the requirements of this standard unless the standard is revised under the approved standards development process. The SDT's assurances to the contrary are not sufficient. This requirement will allow the possibility of sweeping more generators into the requirements than is necessary.
a. In Section A3. reference is made to Bulk Electric System (BES) reliability. Then, in Section A4, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. b. In Requirement R1, instead of the TP providing "instructions", the standard should require the TP to simply "provide" the model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. c. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple generating units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the need to develop these equivalent models. The requirement should be more flexible to allow the GO the option to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate

model. d. In R2.1.1, the GO is required to provide documentation that the generator model response matches the recorded response for a voltage excursion. Since the GO often does not have the capability to run dynamic studies, how will it obtain the “model response” for comparing to the recorded response? We suggest that this requirement be modified to require that the GO “provide the recorded response for a voltage excursion”. As presently written, R2.1.1. can only be required of the TP. Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the voltage data as required in R2.1.1. There needs to be a recognition that the Transmission Planner and Generator Owner will need to work cooperatively on this. The goal is good, but this standard is not nearly developed enough to be a useful standard.
No
It is very difficult to estimate generator performance during frequency or voltage excursions, especially frequency, and the best efforts to provide an estimate may not provide a meaningful result. It is proposed that the TO or TP could achieve the objective better by tracking transmission system voltage/frequency events that could have resulted in abnormal voltages at generating stations, and work cooperatively with the GO informally to determine the generator performance.
a. Most generator voltage relaying is supplied from generator voltage transformers on the low-voltage side of the generator step-up transformer (GSU). It is necessary to provide the information needed for the Generator Owner to relate relay settings on the low-side of the GSU to the No Trip characteristic in Attachment 2, which is based on voltages on the GSU high-side. b. In Attachment 2, please clarify whether the No Trip zone includes the lines, similar to what was done in Attachment 1.
Individual
Joe Petaski
Manitoba Hydro
No
Manitoba Hydro agrees with the concept for manually switched capacitor banks but disagrees for automatic capacitor banks. A model should be required for automatic capacitor banks.
Yes
The implementation plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.
Yes
Yes
Manitoba Hydro is voting negative for the following reasons: 1 - Implementation time frames - the implementation plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. 2 - R5 ‘walk down’ - the requirement of a ‘walk down’ of equipment in R5 is unclear. Manitoba Hydro suggests that the wording be revised to ‘based on an onsite review of the equipment.’ 3 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to “provide other evidence” if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what ‘other evidence’, besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. Manitoba Hydro also suggests that synchronous condensers be included in MOD-026.
No
More detail is required in R4 to ensure that the Transmission Planner can model behavior before and after the disturbance. Information should be provided on how long the unit should take to ramp back to full power following a voltage or frequency excursion that doesn’t cause the unit to trip.
Yes

Manitoba Hydro is voting negative for the following reasons: 1 - R1 - the facility interconnection document required through FAC-001 should supersede Attachment 1 in order to best address local area issues. R1 should be revised to specify this. 2 - NERC IVGTF Task Force Document - the SDT should consider the recommendations from the NERC IVGTF Task Force 1.3 document. Specifically, the recommendations regarding clarifying the potential coordination issues between TPL-001 and PRC-024, clearly defining performance requirements for unbalanced and balanced faults, and defining the performance required during and after disturbances and making clear and unambiguous statements as to what remaining “connected” entails (i.e. how much real power is expected to be delivered post disturbance and how long until the normal pre-disturbance power can delivered) should be considered. 3 - Low Voltage Ride Through clarification - more information is required on the low voltage ride through curve. The GO should be required to provide unit outputs and ramp rates for the different voltage transitions and levels on the ride-through curve. 4 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to “provide other evidence” if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what ‘other evidence’, besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
No
Attachment 1 is confusing, in 2 aspects: a. Attachment 1 starts off with a heading and a blue-shaded page in which the verification periodicity requirements are clearly stated. It is not clear whether or not the 3 by 12 table that follows is a part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with. b. This question (Q2) suggests that guidance is provided on the periodicity aspects of Attachment 1. Is the content in the 3x12 table meant to be guidance? If so, it should be clearly stated so that it does not need to be complied with. If not, where and what is the guidance that the SDT refers to?
Yes
Yes
a. Requirement R2.1: We continue to disagree with the phrase “models acceptable to the Transmission Planners” as it is a potential source of dispute between the TP and the GO. Requirement R1 already asks the TP to provide instructions and model data to its requesting GO but makes no reference to “acceptability”. To avoid potential disputes, we suggest that R2.1 be reworded to: R2.1. Perform verifications using one or more models provided by the Transmission Planner in R1, that include(s) the following information: ….. b. We continue to disagree with Parts R6.1 to R6.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model, especially if such devices are new for which there are no previous simulations to benchmark with. A computer model may fail to initialize due to reasons other than inaccuracy in the submitted excitation control system and plant volt/var control function model itself, and a no-disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. System damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three parts. We suggest this requirement be removed.
No
As indicated in our previous comment, we do not support having a requirement to obtain such an

estimate. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2 and Requirement R3 and the information already received, a TP can apply the following relevant assumptions to its planning studies: i. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; ii. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be more valid than applying the conservative assumption "b" above. We cannot envisage a Transmission Planner to use this additional information if this information cannot be ascertained to be more valid. In short, we do not believe provision of this estimate will provide any more valid assessment of a generator's expected performance than a TP's conservative assumptions drawn from available information already provided by the GO and Attachments 1 and 2. The estimate does not provide any reliability benefit at all. We suggest the SDT remove this requirement altogether.
We believe this requirement is achievable for most cases. However, provision should be given to the Generator Owners which for specific technical reasons are unable to design a generating unit to comply with the requirements. As worded, R5 does not contain this provision. We therefore suggest that R5 be appended with ", or provide the technical reasons why this is not achieveable" after "the following conditions and exceptions".
a. Requirement R1: We believe the words "or generating plant" are missing at the end of R1 since the requirement addresses frequency protection relay settings for new or existing generating unit and generating plant. b. Requirement 4: In the last posting, we commented that: "We do not support the requirement to provide an estimate of the performance of the units during frequency and voltage excursions. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3, the TPs can apply the following relevant assumptions: (i) For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; (ii) For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? The SDT responded that "The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability." We do not agree that removing the 20% increment part goes far enough to achieve a good quality standard. In our view, based in argument put forth in our previous comments, the whole requirement does not add any value to reliability. We again suggest the SDT to remove this requirement altogether." c. Requirement R4.1, last sentence "If the Generator Owner expects the existing unit, generating plant will remain connected…..". We believe the "," before "generating plant" should read "or". d. The proposed implementation plan for both standards conflicts with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of the sentences in Section A5, after "following applicable regulatory approval", of the two standards to the following effect: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."
Group

Pepco Holdings Inc. & Affiliates
David Thorne
No comment
No comment
No comment
No comment
Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition.
Yes
Agree in principle with attempting to quantify the ability of the unit (including affect on plant auxiliary systems) to remain connected during voltage and frequency excursions. However, the present wording of this requirement may not result in sufficient information to fully model the performance of the unit in dynamic studies. It may be more constructive to request a modified set of voltage and frequency ride through curves (similar to Attachments 1 & 2) that represent the Generator Owner’s best estimate of a no trip zone for each unit, taking into account the performance of plant auxiliary systems, as well as any other protection / control setting, or operational limitation, that would prevent the unit from remaining on line within the no-trip zone as defined in Attachments 1 & 2. This would provide the Transmission Planner with sufficient information to fully model the anticipated performance of the unit in their dynamic studies.
Yes
Yes, it is possible to design a new facility to operate within the requirements identified in this standard. However, it may require specification of equipment with higher than normal overvoltage capabilities. Also, significant analyses would have to be conducted on the behavior of plant control systems (exciter controls, boiler controls, etc.), as well as equipment connected to auxiliary busses (including low voltage motor contactors) to ensure that all systems are designed with appropriate ride-through capabilities.
1) If it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with close in three phase faults, then it is equally as important to have them remain on-line for single line to ground faults, which are much more common. During a phase to ground fault at the point of interconnection the faulted phase voltage collapses to zero but the unfaulted RMS phase to ground voltages could rise as high as 80% of the RMS line to line voltage for an effectively grounded system (with a coefficient of grounding = 80%). This is well in excess of the 1.2 p.u. overvoltage requirement presently shown in Attachment 2. As such, for the unit to ride through phase to ground faults at the point of interconnection then the short time 1.2 p.u. overvoltage threshold at the point of interconnection needs to be raised above 0.8 x 1.73 = 1.38 p.u.. In summary, the overvoltage portion of the curve in Attachment 2 should be modified to require the unit to stay

connected with a 138% phase to ground overvoltage appearing at the point of interconnection for up to the expected clearing time of a Zone 1 phase to ground fault. 2) The standard should make clear whether the no-trip zone shown in Attachments 1 and 2 includes the boundary curves themselves. 3) To add clarity and avoid confusion, the ordinate of the graph in Attachment 2 should be labeled Per-unit RMS Voltage Measured at the Point of Interconnection. 4) The current language in Item #1 of the "Voltage Ride-Through Curve Clarifications," which appears on the last page of the standard, may cause problems for generator interconnections on the 500kV system. Most transmission Planners use "nominal" transmission system voltage levels as the "base voltage" in their system models. These are the same "nominal" system voltages specified in ANSI C84.1. In most cases, C84.1 shows the maximum allowable system voltage as 105% of nominal, with the exception of 500kV. For 500kV systems the maximum system voltage is 550kV, and it is routine to operate the transmission system above 525kV (105% of nominal). If the "base voltage" at the point of interconnection used in planning studies is 500kV but the system is normally operated above 105%, then the generation protective systems must be capable of maintaining operation with the continuous voltage at the point of interconnection above 105% of "nominal" (at least for 500kV systems). This being the case the voltage base in Attachment 2 for 500kV systems will by necessity have to be something other the "nominal base voltage" used by the Transmission Planner in their system models. Perhaps this could be addressed by re-wording Item #1 to read "1. The per unit voltage base for these curves is to be specified by the Transmission Planner at the point of interconnection to the Bulk Electric System (BES)." By removing the reference to "the base voltage used in the system models by the Transmission Planner" it eliminates the conflict mentioned above. On the other hand it now requires the Transmission Planner to provide this "other than nominal base voltage for 500kV systems" to the Generator Owners. 5) The word "crest" should be removed from Item #5 of the "Voltage Ride-Through Curve Clarifications," which appears on the last page of the standard . The voltages referred to in this standard are all per-unit "RMS" voltages, not "peak" or "crest" voltages. 6) Typically unit connected generator protection packages, which include frequency and voltage protective elements, are supplied by voltage transformers connected on the terminals of the generator rather than on the high side of the generator step-up (GSU) transformer. For frequency elements, the frequency at the terminals of the generator is the same as on the high side of the GSU transformer. So comparison of frequency protective element set points can be made directly with Attachment 1. However, this is not true for voltage. The generator terminal voltage could be higher, or lower, than the system voltage on the high side of the GSU transformer depending on the voltage drop across the transformer, which varies depending on the generator real power output and whether the generator is supplying or absorbing reactive power. Since this standard requires the generation to remain connected for specific voltage criteria as measured at the point of interconnection, but the voltage sensing protection is connected to the generator terminals, some technical guidance (with specific examples) must be provided to allow the Generator Owner to properly translate these voltage criteria to the voltages seen by the protective relays on the terminals of the generator. Otherwise an incorrect evaluation may result. It is recommended that a Technical Reference Document similar to the "Power Plant and Transmission System Protection Coordination" document developed by the NERC System Protection and Control Subcommittee be produced, or the above mentioned document revised, to provide illustrative examples of how to apply the Attachment 2 POI voltage criteria to voltage sensing protective elements connected to the terminals of the generator.
Individual
Kathleen Goodman
ISO New England Inc
No
While some plants may not have excitation systems, per se, they can have complex reactive coordination controllers, whose settings and functions should be tested and verified.
Yes
No
No, Footnote 4 in the Applicability Section implies comparing simulated unit or plant response to a dynamic system event. This is not acceptable, verifying the model only after an event as called for is completely counter to increasing system reliability. In addition, analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. We feel the

applicability section needs further revision, by requiring only generators above 100 MVA with unit capacity factors above 5 % to test, about 30% of the installed generation in New England does not require model validation. We believe this is a large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being stressed the most and reliable operation is being most challenged. We realize that a model for the generators and associated equipment is supplied in accordance with MOD-012 but we feel the accuracy of such models may be limited and a higher percentage of generator validation is required. Footnote 4 should be changed to allow verification of generator models not required under the applicability to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical.
Yes
While we support the clarifcation of capacity factor, please note our concerns with an exclusion for units with less than a five percent capacity factor that are included with question 3.
We suggest that the language for R4 be made more clear and state as follows. “R4. Each Generator Owner shall provide revised model data or plans to perform model verification5 (in accordance with Requirement R2) to its Transmission Planner 180 calendar days prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response6characteristic. The way the language is currently written, the generator merely has to provide its plans for model verification. This means that 6 months after a change has been made, the correct data still may not have been made available to the Transmission Planning. This could have a significant impact on reliability. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs.
Yes
Yes
The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard appears to allow loopholes which undermine reliability.
ISO New England has comments on Requirement R2 and R3: R2 Although the time duration is acceptable ISO-NE does not agree with the band shown. The band is shown as 0.95 p.u to 1.05 p.u at the point of interconnection. Parts of the New England system have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 pu to 1.05 pu. We also believe there are a number of other parts of the system outside of New England which would have similar concerns. Failure to make this change means that it is acceptable for generators to trip during steady state operation of the system on “low” voltage. Unanticipated tripping of generators under steady state conditions could lead to significant reliability concerns on the system. R3 The ISO would like to reiterate its previous comment that R3 is a significant concern. In the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the “No Trip Zone”, there is no requirement to correct the issue. Instead, the generator must only document the limitation. This completely undermines the intent of this standard. There is no point to setting undervoltage relays to meet the curve if other equipment is still going to trip the plant. This standard appears to simply documenting system concerns rather than identifying and correcting them.
Individual
Keira Kazmerski
Xcel Energy
Yes
Yes
Yes

Yes
Yes
We agree that the current wording (which removes the requirement to provide a probability of ride through) is an adequate means of achieving the reliability goal.
Yes
We believe the requirement is technically achievable, but question whether the additional cost to design and build plants to meet this goal is the most effective way to spend money to increase grid reliability.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Yes
Yes
ATC recommends that the SDT give consideration to the following: 1. In Requirements, R1, bullet 2 – change the wording to be more similar to bullet 1, "obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations". Software manaufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets, allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. 2. In Event Triggering Verification Table, Item 6, Cell 1 – fix typographical error of ". . . system event did not "did not" match . . ."
Yes
Yes
ATC recommends the SDT give consideration to the following: 1. In Requirements R2 – the text refers to "non-protection system equipment" but this terminology is not defined. ATC recommends that the SDT provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. 2. In Requirements, R3 – ATC recommends that the SDT add the requirement that the GO provides the expected duration of the limitation, if it is known.
Group
Florida Municipal Power Agency
Frank Gaffney
The applicability refers to the "bulk power system", e.g., "4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system". The term "bulk-power system" should not be used in the standards as it is ambiguous and should be replaced

with “Bulk Electric System” We do not understand how the Applicability of 4.2.1.2 means. We suggest making the language clearer. R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualfied?
R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the “grandfathering” of existing equipment lmimtations should still be in place. R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst abstains on the MOD-026-1 ballot and offers the following comments for consideration: 1. Facilities a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. 2. Requirement R1 a. For the purposes of NERC standards, “bullets points” are to be considered “OR” statement. ReliabilityFirst believes all the “bullets points” in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) 3. Requirement R5 a. ReliabilityFirst is unclear on the meaning of the term “walk down of the equipment” in the second bullet? ReliabilityFirst request further clarification of the term “walk down of the equipment?” 4. Requirement R6 a. ReliabilityFirst requests further clarification on the term “initializes” as referenced in Subpart 6.1. Is this in the context of excitation control system and plant volt/var control function model initialization within a PSSE application? 5. Section G. References a. ReliabilityFirst recommends removing the references in Reference Section G and place it into a reference type document. Even though this good information, it is not needed in a Reliability Standard. 6. VSL Requirement R2 a. Requirement R2 contains a sub-part 2.2 which is not mentioned in the corresponding Violation Severity Level (VSL). ReliabilityFirst recommends including a VSL covering Subpart 2.2. Here is an example of a “lower” VSL: “For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA in Requirement R2, Subpart 2.2, the Generator provided the Transmission Planner verified models, using plant aggregate model(s), that omitted one of the six Parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.” 7. VSL Requirement R5 a. The VSL for “High” and “Severe” mention Subparts 5.2 and 5.3 though there are no associated subparts referenced in Requirement R5 (there are only 2 bullet points). ReliabilityFirst recommends removing the references to Subparts 5.2 and 5.3. 8. VSL Requirement R6 a. R6 requires the Transmission Planners to “…notify the Generator Owner within 90 calendar days… “, while the corresponding VSL states “The Transmission Planner provided a written response to the Generator Owner indicating…” Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," ReliabilityFirst recommends the following as an example of the “Lower” VSL: “The Transmission Planner notified the Generator Owner indicating whether the model is useable or not useable;

including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R6)”
ReliabilityFirst votes in the affirmative for the the PRC-024-1 standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Requirement R5 and associated Subpart 5.1 a. ReliabilityFirst believes there is a potential conflict and seeks clarification on the choice of words between Requirement R5 and associated Subparts 5.1 and 5.1.1. Requirement R5 begins by stating “Each Generator Owner shall design, build, and maintain its new unit or new generating plant…” which lends itself more to the “planning” type stages while Subpart 5.1 states “When the generating unit or generating plant is operating at or above the minimum sustainable generation threshold” which lends itself to actual “operation” of the unit. ReliabilityFirst questions how the conditions in Subpart 5.1 and 5.1.1 can be utilized if the actual “operation” of the unit has yet to be observed since Requirement R5 is dealing with the design stages of a new unit? 2. Requirement R6 a. ReliabilityFirst request further clarity regarding whether the parenthetical, “(that monitors or models the associated unit),” is associated with all the requesting entities listed in Requirement R6 (RC, PC, TOP, and TP) or just the TP. 3. VSL Requirement R5 a. Requirement R5 states “Each Generator Owner shall design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion.” The VSL states “The Generator Owner’s generator tripped due to a Frequency Excursion within the no-trip parameters set forth in attachment 1”. Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," the language in the requirement is not consistent with the associated VSL. It is not a violation of Requirement R5 if the generator tripped offline within the no-trip parameters, rather it is a violation if the GO failed to design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion. ReliabilityFirst recommends the following language for the “High” VSL, “The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a frequency excursion within the no-trip parameters set forth in Attachment 1. OR The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a voltage excursion within the no-trip parameters set forth in Attachment 1. b. ReliabilityFirst also noted there is no mention of the Subparts 1.1 through 1.7 in the VSL (ReliabilityFirst understands that these are “Conditions and Exceptions” but they should somehow be incorporated into the VSLs.
Individual
Thad Ness
American Electric Power
Yes
No
The tiered approach of MOD-026 Attachment 1 are both unorganized and more complex than necessary, and is confusing as a result. The same approach could be communicated in a more succinct format. In addition, there is content within the attachment that is not mentioned anywhere else in the standard, such as the initial verification of new units and dealing with equivalent units at the same physical location.
Yes
The team might wish to consider if the Transmission Planner should also be included in the applicable facilities 4.2.4 and 5. Point of clarification: one does not “register” units, rather entities are registered for NERC functions.
For section 4.2 we suggest the term “bulk power system” be replaced with “Bulk Electric System”. BES is currently being defined, while bulk power system currently does not have a definition and thus is ambiguous. In the second bullet of 4.2.1.2, one of the words “comprised” or “consisting” needs to be removed as they are redundant. Also, we are confused by the bullets in 4.2.1.2 which should be re-worded to clarify the intent. For example, would diesel generators at a larger facility be in scope of

this requirement? Furthermore, the qualifier between the two bullets should be “or” rather than “and”. For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year. Throughout the standard, “generator excitation control system and plant volt/var control function model” should have an “or” rather than an “and”. The second footnote in requirement 4 could be interpreted to be all-inclusive. Please check the numbering of all footnotes and the pages that those footnotes reference. References should only be made to footnotes on the same page as the referring number.
Yes
AEP agrees with this approach for Attachment 1 only. We also have the following comments about the reference to Attachment 2 in R4. The reliability advantage to be gained from the inclusion of Attachment 2 is unclear, unprecedented and potentially costly. With respect to Attachment 1, any information that a GO can provide about a potential for their unit to trip within the no-trip zone of Attachment 1 will assist the Planning Coordinator in devising a UFLS program for their area, which they are obligated to do under PRC-006-1. A successfully designed UFLS program depends on knowing whether or not generation would trip prior to operation of all stages of UFLS. If it is known that a generator could trip prior to all stages of UFLS, apart from protection settings that would be reported to them under R1 of this standard, the PC ought to know that. Of course, we understand that a GO would not be held accountable under R4 for unknown factors that may result in tripping of their unit within the no-trip zone of Attachment 1. Attachment 1 should be referenced because it would be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the coordination that should take place between UFLS and generation tripping apart from Attachment 1. We also believe reference to Attachment 1 is necessary for consistency in the application of R4 throughout an interconnection. We therefore conclude that it is desirable for overall reliability purposes to reference Attachment 1 in R4. We also point out that curves of the nature of those in Attachment 1 have long existed as guidelines for generation performance during frequency excursions in each of the reliability regions. GOs are familiar with these types of curves, and generating units have been designed with these guidelines in mind. With respect to Attachment 2 being referenced in R4, the reliability advantage is not as clear, but we ask the SDT to consider again that it may be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the possible voltage excursion events that a generating unit may be subject to, and for which it may be desirable to know whether or not a given generating unit would be able to ride through that disturbance. Reference to Attachment 2 may be desirable for, again, consistency in the application of R4 throughout an interconnection. However, in contrast to frequency, voltage is a local quantity and so it is not as critical to system reliability that GOs report voltage excursion trips within the no-trip zone of Attachment 2. The translation of the no-trip zone of Attachment 2 to internal generating plant voltages that would need to be determined is not straightforward, though that translation would need to be made by a GO regardless of whether they would receive point-of-interconnection voltage simulations from a TP or be directed to Attachment 2. We conclude that reference to Attachment 2 in R4 may have reliability benefits that the SDT may want to consider, but we do not believe reference to Attachment 2 is as essential as reference to Attachment 1. If the SDT did not include reference to Attachment 2, that should not have a bearing on the reference to Attachment 1. We assert that, because of the different characteristics of frequency and voltage, it would not be inconsistent to reference Attachment 1 but not Attachment 2.
No
AEP believes that the requirement for new units and plants to not trip within the no-trip zone of Attachment 1 is reasonable, and has precedence in existing reliability region guidelines. To not trip within the no-trip zone of the Attachment 2 is another matter. AEP believes Attachment 2 is inappropriate as a requirement on conventional generation for the following reasons: (1) It has not been found necessary to impose such a requirement as Attachment 2 on conventional generation in the past and we question why this should be proposed now. The appearance of such graphs seems to have been in response to the performance of wind farms that tripped off-line by protective relays when minor fault disturbances occurred on the transmission system. Attachment 2 may thus be an appropriate requirement for wind turbine generators and other non-conventional generation. We ask the SDT why such a requirement now needs to be imposed on conventional generation. If this is being done solely for the standard to appear technology neutral, it does not remove the fact that a new, unnecessary, and possibly onerous requirement is being imposed. (2) Application of Attachment 2 to

conventional generation is not straightforward because of the need to translate point-of-interconnection voltage to plant or unit internal voltage, particularly in the time period following fault removal (.15 seconds). Conventional synchronous generators have a substantial capability to control the voltage they are subjected to during a system disturbance (unlike most wind farms) and whose critical auxiliary systems are usually (and should be) served from the generator bus (low side of GSU) and are thus shielded to some degree by the GSU impedance from voltage excursions on the transmission system. (3) Back in 2005, FERC Order 661-A contained a requirement for wind farms to ride through point-of-interconnection faults up to 9 cycles as determined by the actual fault clearing time at the interconnection station. The final order was thought to be sufficient to ensure wind farm fault ride-through by intervening parties including NERC and AWEA without the need for a graph along the lines of Attachment 2. Justification for the content of the final order was that all generation would be treated equitably. Why does the SDT now think it necessary to impose Attachment 2 on new generation? It would seem that deference to TPL standards for the types of transmission system disturbances where stability should be maintained should continue to be an acceptable ride-through criterion for all types of generation. Reference to Attachment 2 in R5 should thus be replaced by a requirement for all generation to ride through normally cleared 3-phase or unbalanced faults at the POI not to exceed 9 cycles. (4) We do not know the incremental cost to comply with Attachment 2 under R5; however, we believe that it could be very costly to design and build synchronous generating units that would, with a high degree of confidence, remain on-line for any and all disturbances whose POI voltage falls within the no-trip zone. Attachment 2 would also be a new requirement without historical precedent and the SDT has not stated how reliability would be improved. With uncertain reliability benefits and uncertain and potentially high incremental costs to comply, we do not think the SDT is in a position to impose this requirement. For these reasons, we believe that reference to Attachment 2 in R5 should be removed.
R2 is very “wordy”, essentially a single run-on sentence which references yet additional material in its two footnotes, making it difficult to follow. This could be made more clear with the usage of bulleted items. R2.1.1 through R2.1.4 could be and perhaps should be R2.2 through R2.5. R3: We recommend adding “known” to R3 such as “…shall document each known equipment limitation…” to make clear that a GO is not responsible for a cause they are not aware of. R3: The second point under R3 causes the limitation to expire with rating increases. Is a 10 percent or more rating increase a realistic scenario and common enough to justify attention? 10 percent seems arbitrary and this provision could pose a hindrance to rating increases that may supply other reliability benefits. It may be advisable to remove this point. R4.1 should include the Planning Coordinator in addition to the TP because the PC is responsible for UFLS coordination and assessment in PRC-006-1. R5.2 should be removed because of its obvious partiality toward wind farms. R5.6 needs to include coordination with the Planning Coordinator because of the PC’s responsibilities with respect to automatic UFLS. This should also perhaps include coordination with the Transmission Planner for exceptions on voltage excursion ride-through.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes
We agree that there is no useful purpose served by requiring a GO to validate voltage performance on those generators where an active voltage regulator is not used. The modeling of passive capacitor and reactor banks has been established for many years and does not likely need any improvement.
Yes
We support the efforts by all project teams to clearly define the implementation and subsequent periodic evaluation time frames – as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC’s Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-026-1, we believe that the proposed intervals are sufficient to perform the voltage performance model validations; however they are initiated.
No
Ingleside Cogeneration believes that Item 4.2.4 under the “Applicability” section was intended to capture the concept that a Planning Coordinator’s request for additional information is limited to NERC-registered units. However, the language of requirement R5 will predominate, and it reads as

follows: “R5. Each Generator Owner shall provide a written response to its Planning Coordinator,within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant NOT INCLUDED IN THE APPLICABILITY (our emphasis) that includes one of the following” This provides clear instruction that the entire Applicability section may be ignored – even Item 4.2.4. We suggest the following language instead: “R5. Each Generator Owner shall provide a written response to its Planning Coordinator,within 90 calendar days following receipt of a technically justified1 request from the Planning Coordinator to perform a model review of any NERC-REGISTERED unit/plant not included in the Appliability that includes one of the following” 1 Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response Please notice that we also added the footnote under Item 4.2.4 to R5. Although this update is essentially a duplicate, it leaves no doubt to the limits of an exceptional model validation request by the Planning Coordinator. Secondly, MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. We believe that the Planning Coordinator must first engage these entities before issuing such a request to the GO.
Yes
Ingleside Cogeneration strongly agrees with the SDT’s use of the capacity factor calculation used in the GADS system. It is always important to establish links to time-tested parameters – and eliminating any possibility that some other calculation is used.
1. Ingleside Cogeneration LP cannot agree with the change in the applicability section of MOD-026-1, which references generation connected to the “bulk power system” rather than the NERC-defined term “Bulk Electric System”. This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the disrection of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 “Definition of the Bulk Electric System” which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities. 2. What could possibly be a technical justicfication for including generators below that included in the Applicability Section. Without this in the Standard, it leaves it open to whatever the PC is inlinded to do. If you have a “catch all” requirement, you need to have a specific set of technical requirements to limit the PC’s descretiion. 3. Registered Entities below the individual unit thresholds of 100MVA, 75MVA, and 50MVA do not need to be modeled unless there is technical justification. This is a significant burden on small generators. Small generators should only be required to provide model verfication where the PC can show justification through a set of criteria.
No
Ingleside Cogeneration believes that this is an open-ended requirement that allows multiple planning and operations entities – not just Transmission Planners – to require complex assessments completely at their discretion. There is no allowance for the availability of GO resources nor any need for the requestor to provide a reliability justification. Furthermore, we would like to point out that the modeling validation requirements of MOD-027-1 (frequency) and MOD-026-1 (voltage) must, by definition, include the impact of protective relay settings. This means that a need for an estimate of performance is not necessary as real performance data will always be available. In addition, these Standards already allow recourse for a re-validation if Transmission Planners cannot reconcile their models with actual generator performance.
Yes
In our view, the time frame allotted to accommodate PRC-024-1’s frequency and voltage ride-through specifications for new generating facilities is reasonable.
Ingleside Cogeneration LP fully supports the goal to standardize voltage and frequency ride-through settings. In addition, we recognize the benefit to provide accurate generator modeling information and perform regular performance validations to system planners. However, such activities come at a price and compete for the same resources needed to support BES reliability in other ways. Furthermore, there is a cost to develop new PRC-024-1 compliant generation technologies – or to harden existing ones. This may improve reliability over the longer term, but could delay or even rule out the deployment of promising capabilities early on. These are all considerations that we know that the project team is aware of, but we will continue to point out the hidden costs of compliance

wherever we believe that a justification of its advantages is not immediately obvious.
Group
Tennessee Valley Authority GO/GOP
David Thompson
Yes
Yes
Yes
Yes
Yes
No
There are specific areas within the no-trip zone curves in attachments 1 & 2 that would violate nuclear safety limits, which are controlled by the NRC. Also, the turbines of large steam-turbine units may be exposed to unsafe operating conditions within the no-trip zone of the frequency curve.
Group
Puget Sound Energy
Tom Flynn
Yes
Yes
Yes
Yes
None
Yes
No
Steam units appear to have very tight frequency requirements, and the damage is cumulative. In order to protect the prime mover, after several under frequency operations the units may need to immediately trip offline.
Our existing units capabilities are outside those required in the frequency attachment.
Group
Dominion
Mike Garton
Yes
Yes

Yes
Yes
Individual
Brad Jones
Luminant Energy
Yes
Yes
Yes
No
Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross and Net). The standard should specify Net Capacity Factor.
No
An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
No
Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The “maintain” requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.
1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the “no trip zone” of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become “Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds.” For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; “ … unless the generator owner has identified an equipment limitation …” 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. 4. Overall, this standard should address voltage and frequency relay settings only.
Individual
Greg Rowland
Duke Energy

Yes
Yes
No
Footnote 4 – strike the phrase “or plant” in both places, since this only applies to a unit. Also add the phrase “and by demonstrating a reliability need” to the end of Footenote 4. Otherwise, this standard could be made applicable to a small unit that has no impact on reliability.
No
Need to specify “net” or “gross” capacity factor for the calculation.
• R2, 2.1.3 – Please revise to specify total inertia. Total unit inertia should be given to include all coupled rotating elements. The way this is currently worded, it could lead generators to only provide the generator H values. • R2, 2.2 – Insert the phrase “or individual unit” after the word “aggregate”. • Page 15, Equivalent applicable unit - Identically designed generation units are identical in control response, independent of site location. New techniques for validation eliminate the impact of the grid on the validation efforts. Thus, credit for sister unit validations should be available independent of the location of a unit or connected voltage.
No
Generator Owners don’t currently have the capability to provide this information, and will need time to obtain the capability and perform the studies. Requirement R4 should be removed from Effective Date sections 5.1, 5.2 and 5.3 because one, two or three years is insufficient time. R4 should have its own effective date section specifying an effective date of the first day of the first calendar quarter five years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter five years following Board of Trustees adoption. Requirement R4 should also be revised to allow the Generator Owner 180 days (instead of 60 days) to respond to a request and provide an estimate of a unit’s performance during frequency/voltage excursions.
No
The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)”as follows: a. Normal Conditions: ±5% Continuous Duration b. Emergency Conditions: ±10% not specified Duration These Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second is to utilize expensive voltage regulation devices, normally not utilized at power generation plants. This standard shouldn’t dictate a solution to the situation where a generator goes offline due to low voltage on the transmission system, because in many cases the generator going offline may not be a problem for the overall transmission system. In situations where it is a problem, a collaborative effort between the Transmission Planner and the Generator Owner would be the best approach (see AREVA white paper that has been provided to the SDT). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
The frequency and voltage ride-through curves are at the point of interconnection. Conditions inside a generating plant will depend upon how the generator responds to the transient. Models will have to be

built and validated against plant-specific auxiliary equipment performance expectations.
Group
MRO NSRF
WILL SMITH
Yes
Yes
No
It is suggested the following modification to R5 will more clearly mirror the SDT intent as depicted in the question: "…any unit/plant meeting the Registry Criteria not included in the Applicability that includes one of the following…"
Yes
Please give consideration to the following suggestions from the MRO NSRF: 1. In Requirements, R1, bullet 2 – change the wording to be more similar to bullet 1, "obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations". Software manaufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. 2. In Event Triggering Verification Table, Item 6, Cell 1 – fix typographical error of ". . . system event did not did not match . . ." 3. Please restructure requirements and evidence to allow for posted instructions and model data to meet compliance for appropriate requirements such as R1,R2, etc… 4. In the second bullet item under Applicability Section 4.2.1.2, recommend the drafting team remove the word "consisting" and add the word "solely" to avoid confusion. Section 4.2.1.2 would instead read "Each generating plant / Facility comprised consisting solely of …". 5. Recommend the capacity factor test in Applicability Section 4.2 be revised to state: "Applicable units or plants with an average capacity factor greater than 5 percent …" As currently drafted, it is unclear as to whether all units, applicable or not, are included in the calculation of the Capacity Factor (CF). In cases where an entity has a plant with one 60 MVA unit and three 15 MVA units, the units less than 20 MVA would not be applicable per the criteria in MOD-026-1. However, would all units still be factored into the CF calculation? 6. Requirement R6.3 specifies "a disturbance simulation results in …. exhibiting positive damping". Guidance is needed as to what is considered acceptable positive damping. 7. R6 has two periods at the end of the paragraph just before [Violation Risk Factor …] 8. In the applicability section 4.2, the undefined term bulk power system is used. To avoid confusion regarding the applicability, it is recommended the defined term Bulk Electric System be used.
No
Since most existing facilities are likely not designed to a frequency or voltage ride-through standard, the estimate may be very difficult for owners to provide. Staged testing would not be practical for making this determination and engineering analysis may not have the accuracy to make it useful for use by Transmission Planners.
No
A Standard cannot tell us what or how a generator needs to be built. Section 215 of the Federal Powers Act "(i) Savings Provisions, (2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services". We believe that R5 is directing "GO's to design, build and maintain new unit…" and is in violation to the Federal Power Act as stated above. As R5 is written, if an entity builds a new unit and it trips for a voltage or excursion event within the parameters of Attachment 1 and 2, the entity is non compliant. This Requirement seems to be based on future technology that does not exist today. The SDT should state that the parameters of Attachment 1 and 2 "should" prevent a unit from tripping. R5 is written as an absolute and may reduce a new unit from being built. With the risk of non compliance being $1 million per day, it is easier and less risky not to even build a new unit.

The MRO NSRF believes that an entity having to attest to the fact that a generating unit or plant did not trip offers no foreseeable benefit to reliability. As currently stated, Measure M5 could be interpreted to mean that an entity would need to provide a letter of attestation each day or month a generating unit or plant were to function as intended. The MRO NSRF recommends the drafting team either remove this statement or else rephrase the Measure to avoid the expectation that entities verify normal operation. Additionally, as frequency excursion and voltage excursion are not NERC-defined terms nor terms to be defined as part of this project, recommend the terms be placed in lowercase letters to maintain consistency with the Requirement. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a FfrequencyEexcursion or VvoltageEexcursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip. Please give consideration to the following suggestions: 1. In Requirements R2 – the text refers to “non-protection system equipment” but this terminology is not defined. Provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. 2. In Requirements, R3 – add the requirement that the GO provides the expected duration of the limitation, if it is known. 3. Request MOD-026 and MOD-027 be verified for redundancy with PRC-024. In the applicability section the only reference is to Generator Owner. It is recommended the applicability section include a statement that the affected units are only those that are a part of the Bulk Electric System.
Individual
Richard Vine
California Independent System Operator
The California Independent System Operator Corporation has adopted tariff requirements for generator frequency and voltage ride through capabilities that apply to synchronous generators as well as requirements for generator frequency and voltage ride through capabilities that apply to asynchronous generators. As written, the requirements of draft PRC-024-1 apply to both synchronous and asynchronous generators. The ISO requests that the Generator Verification Standard Drafting Team confirm this reading of draft PRC-024-1, and suggests making this clarification in PRC-024-1 as well.
Group
Arizona Public Service Company
Janet Smith, Supervisor Regulatory Compliance
Yes
Yes
Yes
The SDT has done a great job. The requirement is simple, clearer and supports reliability.
Yes
No
This type of data is not going to result into any more accurate simulation than the existing methodology which does not include this data. There are many other inaccuracies involved in modeling and scenario planning for islanding studies. It is a misconception that just by having more complex modeling will improve accuracy and thus reliability.

No
Yes, the requirement is technically achievable. However there is a problem with measure and how compliance may enforce it. Generating units trip for many other reasons other than frequency and voltage excursions. The meaure, as written, will require a GO to prove that the unit(s) did not trip due to frequency or voltage excursion which may be impossible to prove. Even if it finds other reasons, it may be hard to prove that frequency and voltage excursion did not contribute to that other reason. Thus, a GO may be non-compliant unless for each unit trip it can clearly prove that the frequency and voltage excursion did not contribute to trip, which may be impossible to prove.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
Yes
Yes
Individual
Daniel J Hansen
GenOn Energy
Yes
Yes
In Attachment 1, the title “Consideration for Early Compliance” should be changed to “Comliance for Prior Verification”
Yes
Yes
Yes
Yes
Conditionally yes; unconditionally no. It is achievable for any plant with a modern AVR and unit connected auxiliaries. Problems arises for unique circumstances that may require auxiliaries that are not unit connected (directly connected to transmission systems). Existing plants orginally designed with unit connected auxiliaries have been forced to extend auxilary power feeds directly from transmission level voltages. It is believed that transmission system performance better than Attachment 2 is available at the majority of locations, and therefore, it is not necessarily appropriate to make this the design criteria for every future generating station.
Thank you to the SDT for you efforts to produce a quality standards. R3 should be worded in a similar manner to R4. “The Generator Owner shall document the estimated equipment limitations…” The problem with a requirement like R3, is that documenting “each” equipment limitation on older

facilities will contain uncertainties and unknowns. The implementation schedule for the requirements will be more efficient if the schedule is aligned with the PRC-019 schedule rather than having the two similar efforts on different tracks.
Individual
Patrick Brown
Essential Power, LLC
Yes
Yes
Yes
Yes
Yes
Yes
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
No
If the GVSDT intends to incorporate definitions or calculations from Appendix F of the GADS Data Reporting Instructions, the relevant information needs to be expressly incorporated, perhaps in an additional attachment to the standard. Requirements that refer to outside materials are not helpful and should be avoided (notwithstanding the desire to avoid a future need to modify the standard to the extent that Appendix F is amended from time to time in the future).
Yes. See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: • "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and • Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating plants/Facilities with total generation greater than the thresholds established in the Applicability

section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6."
Yes
No
While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Kirit Shah
Ameren
Yes
No
The comments and guidance of the GVSDT are greatly appreciated. However, we have a concern/question, how would the periodic verification/testing requirements for MOD-026 would align with other such requirements in place for MOD-024, MOD-025 and with reporting requirements of MOD-012 and MOD-013? We would like the GVSDT to consider a well-coordinated periodic verification and reporting needs for all such requirements to provide the GO flexibility to schedule their tasks to meet these requirements without undue burden to take facility out of service at different times.
No
We believe and recommend that this should be the responsibility of the Transmission Planner rather than the Planning Coordinator. At a minimum the language should state “Planning Coordinator and Transmission Planner”.

Yes
(1) The requirements 4.2.1.1 and 4.2.1.2 refer to bulk power system (BPS). We suggest that GVSDT includes definition of BPS in the standard. (2) We suggest that GVSDT clearly specify that "point of interconnection" referred to in R2.1.1 to be the same as defined in PRC-024-1. (3) In Attachment 1, Row 4 it seems to imply to us that some use of "Sister Units" is allowed to meet the requirement. . We suggest that the GVSDT clarify and include this option in the body of the Standard (preferably) or in Attachment 1 as an option? (4) Requirement R2.2 states that an Applicable plant with gross nameplate ratings of the units < 20 MVA should use a plant aggregate model. Can the GVSDT clarify the type of model and provide example for each? (5) There are 17 technical papers referenced in Section G of the Standard. Would the GVSDT make them available on the NERC website? (6) For Requirement R3, we did not find anything in the standard that specifies how closely a model response must match the tested response of a generator. We believe that unless this is clearly specified, it could lead to disagreements between the Generator Owner and Transmission Planner over what constitutes a verified model.
No
At the end of R4.2, we suggest to add “the Transmission Planner’s voltage recovery characteristic from R2 part 2.1.1” since that may well have bearing on the estimate. We understand the reasons for such studies, but we ask the GVSDT to consider the fact that more than 60 days may be needed to estimate generating unit performance especially the first time it is done for each unit. As long as this applies only to generator frequency and voltage protective relaying (and not to station auxiliaries) developing these estimates in the time frame mentioned earlier is achievable.
No
(1) We understand this to include generating plant auxiliary load based on the GVSDT reply to our draft 2 comments. If still is the case, please clarify and explicitly insert “including its auxiliary systems” after generating plant so that all GO understand it. (2) Many 480V class contactors drop out in the 70% to 80% voltage range, so we doubt they’ll ride through the 2 to 3 second portion of the voltage excursion. The middle portion of your voltage excursion curve is more stringent than the CBEMA and SEMI curves, both of which recover to 80% in 0.5 sec. Transmission system protection in our system will clear faults faster than the proposed voltage excursion curve, thus in effect yielding a voltage recovery curve with shorter durations for the voltages specified. We would ask the GVSDT to consider what we feel is a more realistic approach of designing a new generating facility to the Transmission Planner’s voltage recovery characteristic allowed for in R2 part 2.1.1 is achievable now. What was the basis on which the proposed voltage excursion curve developed?
(1)Under Applicability it should state that ‘all existing generators meeting registry criteria’ and also ‘new generating units that will meet the registry criteria.’(2)Please modify the Effective Date and Implementation Plan to provide a five year phase-in to match that of the companion PRC-019-1. Generator voltage protective relaying must be reviewed in both these standards, and we believe that doing so on the same schedule will yield a better coordinated result and less confusion. Each of these standards will consume valuable resource time and the efficiency of reviewing each generator concurrently will improve BES reliability. (3)Please add ‘R1, 1.3 If clearing a system fault necessitates disconnecting a generator, then this action is acceptable within the “no trip zone”.’ This affords the same practical reality recognized for voltage excursions.(4)Please be clearer regarding the Voltage Ride-Through curve. Attachment 2 Voltage Ride-Through Curve Clarification #2 could be interpreted to imply that the curve is based on three phase faults. But the inclusion of #5 states that phase-to-ground or phase-to-phase voltages (minimum or maximum as appropriate) are assumed. Of course, for a three phase fault the each phase’s voltage is equal. So we interpret #5 to mean that the actual fault type to be simulated should match the Transmission Planning criteria, which for example may be double or single line to ground faults with delayed clearing. We recommend to the GVSDT to align this with the TPL standards, which use three phase fault or single line to ground fault with Normal Clearing, but only single line to ground fault with Delayed Clearing. We would appreciate an example or in depth explanation to tie these together. Please annotate Attachment 2 with references to R2 and clarifications on page 18. (5)Delete ‘or generating plant’ from R1, R2, and R3 to be clear that the generating plant auxiliary loads are not subject to these requirements. Alternatively, restate R3 as “…that prevents a generator frequency or voltage protective relay generating unit or generating plant, from meeting the criteria in Requirements R1 or R2 including study results, experience from an actual event, or manufacturer’s advisory” to be consistent with R1 and R2. (6)At the end of Requirement

R4.2, please add “the Transmission Planner’s voltage recovery characteristic from R2 part 2.1.1” since that may well have bearing on the estimate. (7)From our perspective, Requirement R5 doesn’t make sense for a newly designed generator. We would suggest the GVSDT to realign M5 to be prospective and to require the GO to provide design basis evidence appropriate for the stage of design of new generators. In early conception stages, the GO would request the Transmission Planner’s frequency and voltage excursions. Then the GO would design the generator train and auxiliary system to ride through, and if infeasible, request technical exceptions. Late in the design process the generator frequency and voltage protective trip settings would be determined; it would be appropriate at that time to provide them R6 requests for future system studies. (8)For Requirement R6 we oppose providing this specific information to all these functional entities, given that they are getting the R4 estimate of performance during such excursions. (9)If R6 is retained, please make the following changes: (a) We strongly prefer a reporting of exceptions to the standards frequency and voltage excursion ride-through curves rather than reporting all these relay settings. Use PRC-006-1 Attachment 1 page 28 of that standard for frequency reporting. Develop a similar envelope for voltage reporting. If a Transmission Planner’s voltage recovery characteristic allowed for in R2 part 2.1.1 differs that should be provided for the generators in their area. Generator Owners would then report exceptions. (b)Insert “frequency and voltage” between generator and protection in the first line.(c)Delete “and within 30 calendar days of any change to those trip settings,” because this creates an open ended obligation on the GO. (10)We would suggest the GVSDT to not capitalize frequency and voltage excursions as they are no longer defined terms. (11)We suggest the GVSDT to replace the time-based or binary VSL for R1, R2, R3, R4 and R6 with a VSL in terms of the GO % of MWh produced for the time period of violation. This better characterizes the risk to BES reliability. We propose <5% for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe. As presently proposed a generator with no operating hours could cause a GO to incur a Severe violation though it posed no risk to the BES. (12)From our perspective, the VSL for R5 doesn’t make sense for a newly designed generator. We suggest, a time-based VSL with x days late in providing R4 or R6 type information. . In this regard, we propose to the GVSDT 30 days late for Lower, 31 to 60 days late for Moderate, 61 to 90 days late for High, and >90 days for Severe. (13)PRC-024-1, R2.1 states that generator terminal voltage refers to Attachment 2. However, in R2 itself, footnote 3 states that voltage excursion applies to point of interconnection, meaning the GSU high-side. We suggest the SDT resolve this discrepancy. (14)Attachment 2 should include footnote similar to footnote 3 provided for R2.
Individual
Larry Raczkowski
FirstEnergy Corp
Yes
Yes
Yes
Yes
FirstEnergy would like to make the following comments on this standard: 1)Under the Applicability section 4.2.1.2, the use if the term "common bus" should be clarified as either the low-side or high-side of the GSU. 2)Footnote 1a on Page 2, says that “... the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.” While we understand that the excitation system supplies the generator field, there is a separate Model for the Generator (typically GENROU). We suggest omitting the word generator from the footnote to avoid confusion. 3)Suggest rewording 2.1 to begin with, “Provide models acceptable to the Transmission Planner, including verified parameters ...”, rather than “Perform verifications ...”. The GO provides information on applicable models as well as the parameters. The TP actually runs the models to determine system impact. 4)Requirement 2.1.1 requires “Documentation demonstrating the applicable unit’s model response matches the recorded response for a voltage excursion at the applicable unit’s point of interconnections from either a staged test or a measured system disturbance. •Please define or qualify the term “matches”. This is a subjective term, subject to interpretation of results; i.e., what %

error is considered “matching”. •Refers to recorded response “… at the applicable unit’s point of interconnection …”. This should be reworded to “at generator terminals”. An excitation system controls to the generator terminals since this is where Voltage and Current inputs to the AVR originate. Further, this is where measurements are taken during dynamic testing. •"a measured system disturbance” is not practical for a GO, and should be eliminated. DME is owned by the TO, and do not have access to results of disturbances.
Yes
Yes
Individual
Mark B Thompson
Alberta Electric System Operator
The AESO does not support the changes made to the Curve Details, in the Voltage Ride-Through Curve Clarifications section of the standard, in particular the use of the term “base voltage” . In many parts of the Alberta transmission system the maximum normal operating voltages are significantly higher than 1.05pu of than the “base voltage” used in studies. The system has been studied, planned and designed around these higher voltages. For example; in a study the base (nominal) voltage is chosen to be one per unit (1.0 pu) equals 240 kV but in the study area typical operating voltages are 256 kV (1.07 pu) and can be as high as 1.10 pu.
Group
PPL Electric Utilities and PPL Supply NERC Registered Organizations
Annette M. Bannon
Yes
Yes
No
The term “standby” in footnote 2 on p.2 bears definition. Is 5% capacity factor the criterion to be used in establishing standby status? If so, it would be best to make this standard entirely unit-based, eliminating all references to plants.
Yes
a. Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of running dynamic models or representing within the model the system we connect-to. R2.1 1 should require the TP, not GOs, to run models and develop the referenced documentation (or, if the result is not suitable, open a dialogue per R3). The same comment applies for R2.2. b. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted

to comply with MOD-026. It was stated in the 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion is not included in the draft standard. c. We suggest replacing “rotational inertia” in R2.1.3 with “inertia constant (H),” the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. d. The 4/6/10-year periods specified in paras. 5.1.1-5.1.4 and 5.2.1-5.2.4 on pp. 3-4 of MOD-026-1 should provide for existing plants enough time to catch a disturbance of sufficient magnitude for verification purposes; but the one-year allowance in row 3 on p.15 for plants that are new or have replaced controls equipment may prove inadequate, especially since (per comment 5b above) we don’t currently know what sort of transient is needed. At least a four-year window should be granted for the initial verification. It is also unclear how one decides up-front the applicability of this standard to a new facility. The past-years test of para. 4.2 cannot be used; and a unit anticipated to have less than a 5% capacity factor may prove otherwise depending on market conditions or other factors. In any event the one-year verification limit for new and modified units is inadequate if it takes longer than this amount of time just to determine whether or not MOD-026-1 is applicable. e. The use of the undefined term “technically justified request” in R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? Further, the 90 day time period should not begin until both parties fully understand the “technically justified request.” f. The means by which a walk-down would lead to identification of model parameters in the second bull-dot of R.5.2 is not understood.
No
Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of predicting responses to voltage and frequency excursions. This is especially the case when one must, per R4.1, engage in the phenomenal complexity of calculating the transient performance of auxiliary buses and identifying the short-term drop-out thresholds of the multitudinous pieces of equipment they power. The references in R4.1 and 4.2 to experience, actual event histories or sound engineering judgment as alternatives to a computer model are not helpful, because meaningful assessments can be made only if one has relevant data (i.e. high-speed records of past disturbances, at HV, MV and LV voltage levels) and issue a PV. Further on the subject of complexity, there are a variety of aux bus configurations possible for our multiple-unit plants, any one of which could be deemed normal depending on circumstances. Having to check every aux bus configuration for every units-running combination would be unduly burdensome, even if it were possible. The fact that R4 cites “Frequency/Voltage Excursions” (apparently meaning simultaneous deviations of these parameters), while R5 is careful to refer to “frequency excursion or voltage excursion,” adds confusion. Another concern is that the boundary conditions for the above-described analysis are presently undefined, with the standard invoking instead a “dynamic simulation provided by the Transmission Planner.” For the reasons stated above, the proposed requirement R.4 should be eliminated.
No
It is possible for new facilities to buy steam turbines that permit operation in accordance with Att.1. We cannot confirm that it is possible to do so for all fossil unit sizes or generation unit types, however, and recommend that question 7 above be put to OEMs. This is particularly the case for gas turbine engines, for which the limiting factor may be surge avoidance rather than resonance margins. Note also that such units may auto-unload at abnormal frequencies. This action may not provide the grid ride-out capability wanted, despite satisfying R5’s no-trip requirement. The general acceptability stated above for steam turbines bears clarification, however, because OEM guidelines for off-frequency operation typically have a lifetime basis. That is, each transient results in cumulative fatigue damage. The frequency curves of PRC-024-1 are consequently not acceptable for an unstable grid that often swings to the max-specified deviations, and a statement should be added to this standard to the effect that the no-trip zones of Att. 1 apply for frequency excursions to the extremes no more frequently than once per decade. Att. 2 presents a problem in that the deviation location is specified to be the point of interconnection, but GOs are being asked to confirm that all MV and LV devices required to maintain the unit on-line will not drop-out. An excursion to -10% voltage on the 230 kV span would correspond to -10% on the LV and MV systems only for theoretically ideal transformers, and the actual transient at critical loads may be greater. It would not be possible in any event to get OEMs to guarantee that the auxiliary equipment they supply will not drop-out for the Att. 2 excursions of 10 minutes at -10% voltage, 2 sec at -35% or 0.2 sec at -55%. The industry standard on this subject is ANSI C84.1, which stipulates voltage boundaries of +/- 5% for continuous operation

and +/- 10% for emergency operation of no specified duration. If NERC feels that the criteria of Att. 2 are important for BES reliability they should start by asking the appropriate ANSI and IEEE committees to revise their standards accordingly. We cannot support PRC-024-1 until its criteria become the nationally-accepted norm, because we otherwise would be making a commitment that it is impossible to fulfill.
a. A standard-specific definition of the word “plant” is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit’s behavior. b. Clarity is needed for the expression, “it does not trip,” in R1 and R2. Does this mean that the protective relaying does not trip, or that the unit does not trip? In the latter case do the requirements pertain only to interlocks, or do they also cover disturbances that may result in a trip? Such differentiations were clearly spelled-out in the PRC-005-2 draft currently out for voting, and they are needed here also. What seems at first to be relay-setting requirements may in fact also incorporate aux equipment drop-out, invoking for existing equipment the concerns stated above in response to question 7 (with regard to designing a standard based on a technology for which vendors may not guaranty performance).
Individual
Jeanie Doty
Austin Energy
Yes
No
Per R1. the TP should provide periodicity.
Yes
The standard is not applicable to the Planning Coordinator. Does the SDT mean TP?
No
The NERC Glossary is the correct reference for definitions used in the Standards. Referencing GADS is not appropriate.
The standard drafting team may consider adding the sentences in footnotes 2 & 3 directly to section 4.2 Facilities to avoid potentially unecessary complexity. Also in section 4.2 Facilities, the term bulk power system (BPS), not BES is used. Would use of BES instead of BPS remove the need for footnote 2 without changing the overall intent of the SDT?
Yes
Individual
Randall McCamish
City of Vero Beach
The applicability refers to the “bulk power system”, e.g., “4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system”. The term “bulk-power system” should not be used in the standards as it is ambiguous and should be replaced with “Bulk Electric System” We do not understand how the Applicability of 4.2.1.2 means. We suggest making the language clearer. R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualfied?

R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the “grandfathering” of existing equipment lmimtations should still be in place. R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves.
Individual
Christine Hasha
ERCOT
Comment 1: Requirement R2 and voltage ride through curve in the PRC-024 Attachment 2 are applicable to the voltage at point of interconnection to the Bulk Electric System (BES). However, in requirement R2.1 “When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:” The clarification is needed for R2.1 that describes how the generator terminal voltage will affect the applicability to this requirement. Comment 2: In the attachment 1 and attachment 2, it is not clear if a unit can be allowed to trip instantaneously under extreme high voltage or high/low frequency occurred during and post disturbance period. For example, the physical limitation requires a wind farm to trip the turbine instantaneously when voltage is above 1.25 pu. If there is a short duration of overvoltage, 1.3pu for 0.15 second, during and post disturbance period that cause the wind farm trip the turbines, does this wind farm violate the requirement as stated in attachment 2 that requires the wind farm to remain in service for 0.2 second when voltage is above 1.2 pu?
Comment 1: In the Applicability section, it is not clear in 4.2.3.2 which units/plants are required to meet this standard. For example, a generating plant that is greater than 75 MVA and consisted of 75 1MW generating units, is this generating plant required to meet MOD-026-1? Another example, a generating plant that is greater than 75 MVA and consisted of one 45MVA generating unit and two 15MVA generating unit, is only the 45MVA generating unit required to meet MOD-026-1?
Individual
Ed Davis
Entergy Services
MOD-026-1 R2.1.1 is: 2.1.1. Documentation demonstrating the applicable unit’s model response matches the recorded response for a voltage excursion at the applicable unit’s POINT OF INTERCONNECTION from either a staged test or a measured system disturbance. We recommend the POINT OF INTERCONNECTION be changed to GENERATOR TERMINALS.

Individual
Patrick Farrell
Southern California Edison Company
Yes
Yes
Yes
Yes
While an active closed-loop voltage regulation function is useful in distinguishing transient voltage and frequency responses within mere cycles or seconds of perturbations, a similar requirement should be added to MOD-026-1 to require variable generators who were exempted from the standard by the condition added to Attachment 1 to provide similar plant voltage/var control, design, and test data to the Transmission Planner. The automatic switching of capacitor banks and reactor banks can play a role in maintaining the voltage stability of the system.
Yes
No
The language in the requirement is acceptable, but the frequency curve identified for generators is too restrictive for hydro facilities, which are often dispatched to provide VAR and voltage support. SCE's hydro generation plants operate at very low RPM, which provides them with the ability to operate safely above (60-78 Hz) and below (<58 Hz) the frequency curves in Attachment 1 and Attachment 2, respectively. As a transmission operator, SCE applies this flexibility in its hydro generation plants to compensate for system instabilities resulting from VAR and voltage excursions. In addition, SCE's employs its hydro plants to support system restoration.
The standard should allow for wider regional variances - for example, WECC allows lower frequency and voltage excursions.
Group
Western Electricity Coordinating Council
Steve Rueckert
Yes
The introduction to this comment form indicates that "The typographical errors in R2.1.1 language has been corrected to clearly state expectation that, “The unit or plant’s model response matches the recorded response for a voltage excursion at the generator or plant point of Interconnection..." However, the versions posted for review (clean and redline) do not indicate that the "unit or plan's model..." They say the "applicable unit's model response matches..." There is no reference to plants in part 2.1.1
I am unsure of the intent of the phrase "estimate of the performance of the units during frequency and voltage excursions." Is this intended to mean that the owners should estimate whether or not the unit will stay connected, or provide some estimate of the unit's dynamic performance and response to an event? I also don't understand the purpose of this requirement. If models already exist and are available to the Transmission Planners, then the owners should be validating the model. As part of the validatio process the owners should be able to tell the Transmission Planner what the performance will be. Is this for units for which models have not been validated?

The Attachment depicting the No Trip Zone for frequency excursions for the WECC Interconnection is incorrect. It is missing one of the steps from the materials provided to the drafting team in July. The table is also missing a step. This must be corrected. In my opinion, the table identifying the High and Low Frequency Duration information is hard to interpret. As depicted, the table appears to be giving a range of time that a generator must stay interconnected at a specific frequency. I am not familiar with the requirements in other regions, but in WECC, we have specified a specific time that a generator must stay interconnected for a frequency range. In looking at the WECC table included int he draft standard I would not be able to discern how long a generator had to stay interconnected if the frequency were at 59.0 Hz. Similarly, I have the same problem with the information in the tables for the other interconnections. After discussions with drafting team representatives, an suggested revision for the format of the tables has been proveded to the drafting team for consideration. Even with the inclusion of the (not including the lines) statement on the No Trip Zone plot, it is still difficult to determine minute specifications from the plot. Depending on the quality of the diagram and the thickness of the line, there will still be the potential for debate. I believe a solution is to indicate the plot is for illusrative purposes only, and the specifics are provided in the tables. With the suggested format changes provided to the drafting team, there should be no room for speculation. Whether the Off-Nominal Frequency Capability Curve is used for illustrative purposes as suggested above, or for specifying details, it is difficult to view as presented. One option would be to provide three individual plots, one for each interconnection, and include them all as Attachment 2. This way you could still refer to Attachment A in Requirement R2, and perhaps add language such as "appropriate plot in Attachment 2" to the requirement.
Individual
Ken Wofford
Georgia Transmission Corporation
Yes
Yes
Yes
Requirement 5 seems to imply that GO’s must provide a written response regarding units below the Registry Criteria unit MVA thresholds (< 20MVA) if a Planning Coordinator provides a technically justified request to perform a model review. Can the SDT confirm this intent? Additionally, there could be some confusion with the language as written to imply the PC’s “technical justification” includes the bulleted items of R5. GTC is assuming the SDT’s intent is for the “GO’s written response” to include the bulleted items and therefore requests additional clarity. GTC recommends the following: Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant not included in the Applicability. The written response shall include one of the following [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]: • Details of plans to verify/correct the model documentation and data as needed (in accordance with Requirement R2) • Corrected model documentation and data including the source of revised model data.
No
We ought to be able to verify FIDVR mitigating machines below 5% capacity factor.
Yes
Don't know
Comment on R6, Severe VSL. Time limit is within 60 calendar days, however the time limit for R3, R4 and R5 state 61 calendar days. Wording for Severe VSL for R3, R4, R5 and R6 should have the same time limitations of either “...within 61 calendar days” or revised so that the documentation was “communicated greater than 60 calendar days....”.
Group
Southern Company
Antonio Grayson

Yes
Yes we agree with this concept. It is not practical, and there is no benefit to reliability, to require validation for units which do not include an active closed-loop voltage regulator function.
Yes
A periodicity of ten years between model verifications when there are no special circumstances is appropriate. What is the basis for a ten year re-verification for units where no changes to the excitation system have occurred? A ten year verification basis for an non-modified digital excitation system does not seem to be justified.
Yes
Allowing a Planning Coordinator to request additional model information only if technical justification demonstrates a mis-match between the measured unit response and the model's predictied response is appropriate. Even if the unit was a contributor to a stability limit, additional model information is really only needed if the model did not sufficiently emulate actual equipment response.
Yes
We agree that the collection of preliminary excitation control system model data from the equipment manufacturer is outside the scope of this standard. Also, any pre-COD staged testing to collect equipment responses to be used to verify the model can be required via Interconnection Agreements. It is understood that any equipment responses collected through pre-COD staged testing with final equipment settings in place that is subsequently used for model verification per the Requirements in the standard would result in fulfilling the requirements for model verficiation for the next 10 years per the Periodicity Table or until a special circumstance occurs leading to an earlier model re-verification as detailed in Requirements R3, R4, R5, or R5. The limitation to allow sisterhood for only those units at the same physical location should be extended to all identical units for the same GO/GOP - a sister is a sister is a sister. The GO should be allowed to take credit if he can show that the physical location is not a factor in the comparison. In section 4.2.1.1, and other places, we don't understand the use of "bulk power system" –shouldn't this be "Bulk Electric System". In 4.2.1.2, second bullet, eliminate the word "comprised" as it is redundant with "consisting". The same redundant use of "comprised" is insection 4.2.2.2 and 4.2.3.2, second bullet. In R2.1.4, the intended information is not clear – the closed loop voltage regulator part is not needed – it is part of the previous wording. In R2.2, replace "For plants" with "For applicable plants". Please add "where applicable" each time the "plant volt/var control" is used. Due to R5, the Planning Coordinator should be listed in the 4.1 Functional Entitles. R5 is confusing – the bullet items list what the GO response should include, but the sentence is written such that the list is what the model review must include. In R2.1.1, please insert "or voltage at the generator terminal" to "at unit's point of interconnection".
No
We cannot agree with the approach of Requirement R4 due to the uncertainty about how to estimate the performance of "each" plant system, sub-system, or component that could cause the unit to trip for the voltage excursion profile of Attachment 2. For most units, this estimate may vary from a few cycles (examples: dropout of low voltage motor contactors or an auxiliary control relay) to up to 1-2 seconds (examples: tripping of boiler controls or medium voltage motors). Determination of a more accurate time estimate would require detailed dynamic analysis, which would entail significant engineering study and involve assumptions and judgment based on experience. Data from actual event histories, if available, would likely not match all points of the Attachment 2 time-voltage profile. The voltage excursion profile needed for an evaluation would be the voltages present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. Without detailed analysis, only a rough estimate could be made which would probably be of limited value for transmission system analyses. A conservative approach would be the "go/no-go" approach and identify those units that are likely to trip for a specified voltage excursion. For the current requirements stated in R4, the 60 day time requirement would be a significant challenge for a GO to meet for a single unit. For GOs who have a large number of units and limited engineering resources, the 3-year phase-in period will be impractical to establish on many units the estimated performance of "each" plant system, sub-system, and component that could trip. Bottom line is, the concept may seem simple enough in principle, but these requirements cannot be practically met. We believe the scope of the standard should be limited to identification of the protection function trips per R1, R2, R3, and R6 only.

No
We recommend R5 be eliminated. New plants should be subjected to the same requirements as existing plants. The design of plant systems, sub-systems, and components are based on industry technical standards (ANSI, IEEE, ASME, etc.). Establishment of new NERC plant performance requirements must be coordinated with the industry through those standard processes. We believe significant R&D will be required to achieve significant new plant design requirements that can be used to revise the industry technical standards and that plant, system, and equipment designers and builders can meet. The scope of systems and components that must be addressed includes, but is not limited to, turbine generators, transformers, feed pump systems/controls, boiler control systems, reactor protection systems, emergency diesel generators, AC motors, pumps, fans, AC motor contactors, auxiliary relays, etc. In addition, significant costs will be incurred by the industry that we believe demand further justification.
Yes: 1) We respectfully disagree with the SDT's response to our prior comment related to maintaining the safety of the reactor core at nuclear plants for voltage or frequency transients. The intent of our comments is to ensure that application of this standard to nuclear units is coordinated per the requirements of NUC-001. Employing any changes to the grid frequency and voltage ride-through requirements may impact the licensing and design basis of nuclear facilities. NUC-001-1 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown. This is achieved through development of Nuclear Plant Interface Requirements (NPIRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements (NPLRs) and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities. The NPLRs are requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance or transient condition is important. It is essential that this process be followed closely in attempting to apply any new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant’s licensing and design basis. The safety of nuclear power plants is of paramount importance. 2) R1, R2, and R3 state “each” non-protection system equipment limitation. This should be clarified to state "each non-protection system equipment limitation associated with the applicable protection function." 3) Event monitoring equipment required by M5 will be a significant burden on GOs to only prove a negative. We believe M5 should be removed from the standard, because the benefits gained do not justify the costs.
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
LADWP agrees with this concept since no feedback signal is available (in an open loop control) to regulate against for Setpoint (Reference) control.
Yes
LADWP agrees with the guidance.
LADWP recommends that “technical justification” is defined and/or replaced with more specific language, i.e.: “Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if documentation such as model structure and data values for the excitation control system demonstrates the ....”
Yes
LADWP agrees with this revision.
LADWP supports the language under Attachment 1, “Consideration for Early Compliance”.
LADWP does not have comments on this question at this time.
LADWP does not have comments on this question at this time.
LADWP supports the following comment below: “The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the

underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.”
Group
Bonneville Power Administration
Chris Higgins
The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Individual
Russell A. Noble
Cowltiz PUD
Yes
Yes
No
Technical justification should also include reasonable demonstration that the improved model will improve the Reliability of the Bulk Electric System.
Yes
Cowlitz PUD respectfully disagrees with the use of the statutory term bulk[-]power system in the applicability section of any reliability standard. This term is not adequately defined to be used anywhere excepting arguments as to whether a proposed standard falls within the jurisdiction of the Federal Power Act of 2005. Use of the statutory term will hamper any future efforts to revise the Statement of Compliance Registry Criteria. The Bulk Electric System is a subset of the bulk-power system. If the intent of the SDT is to include any generation of stated MVA name plate capacity connected to a “transmission system” operated at an undefined voltage, the result will be to defeat

work being done to technically justify exclusion of certain bulk-power system facilities which have no substantial impact on Reliability. If however, the intent of the SDT is to follow the Statement of Compliance Registry Criteria and imply that the “BPS” is equal to the BES, it is preferable to specify generation connection voltage than use BPS. Cowlitz agrees that non-BES generation may need to be included in this standard’s applicability section (as users of the BES), however specific generation that a particular GO may own which by itself would not have required registration of the entity should not be inadvertently included in the applicability of this standard.
No
Cowlitz is only concerned with the 60-day response time. The responding entity should be given some leeway to negotiate a delivery time if the 60-day response is not feasible. Otherwise, substandard estimates will be provided to avoid violation of the standard.
No
Cowlitz supports Clark County PUD's position. Please verify the following: The problem is that PRC-024 skips a frequency step in the low frequency operating area. The generator frequency ride through of Attachment 1 is inconsistent with the current WECC Off Nominal Frequency plan and the frequency ride through in the proposed WECC-0065 regional criteria. The PRC-024 ride through could cause a combustion turbine to operate at 58 Hz for a duration that would cause damage to the turbine blades. The current WECC ONF ride through avoids this.
Individual
Michael Goggin
American Wind Energy Association
Yes
Yes
Yes
Yes
Yes
Yes
Yes, the feedback we have received from wind turbine manufacturers is that, if such a standard were not applied retroactively and were implemented with a grace period extending at least several years into the future, wind plants would be able to meet these requirements.
Individual
Scott Berry
Indiana Municipal Power Agency
no comment
no comment
no comment
Yes
IMPA believes that the reference of “bulk power system” should be replaced with Bulk Electric System throughout the standard. Bulk power system is used in the Compliance Registery, but it is not a NERC defined term. FERC even agrees that bulk power system goes beyond the Bulk Electric System (FERC Order 693). IMPA is troubled by the requirement in R2.1.1 that requires a voltage excursion from a staged test or a measured system disturbance. Are there an ample supply of contractors or consultants that can perform such a test? What is the risk to a unit to perform the staged test?

No
IMPA does not agree that there would be any gain in reliability by requiring Generator Owners to give an estimate on the performance of a unit or the overall plant during a frequency or voltage excursion. Will such a request include specific parameters that would be expected on the system to narrow down this imposition of an estimate upon the Generator Owner? Will Generator Owners be capable of providing an estimate that may be required under this item? In addition, the Transmission Planner is to provide the dynamic simulation of the voltage and frequency profile at the point of interconnection. There is no guidance in the Standard as to how often or what means will be used to submit the (new) profile(s) to the GO – will it be annually, seasonally or?? IMPA also has concerns with attempting to accurately predict the ride-thru capabilities of a generating unit/plant on a consistent basis. As an example, if the unit/plant was operating during an extreme and prolonged period of heat and humidity it's characteristics and ability to ride thru a frequency and/or voltage event will be different than if running during the opposite – extreme cold and wind. Many of the unit/plant auxiliary systems may be located in areas that are not climate controlled and it would be extremely difficult to consistently predicte how they will react during temperature extremes.
No
Is the technology to meet this requirement even currently available to a newly built generating facility? To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the gird on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available? IMPA believes that this standard will be reviewed by NERC in five years or sooner and at the time the SDT can revisit this possible requirement to see if the technology to keep a generating facility on line during a voltage or frequency excursion has been proven. Or a condition could be added that says new units shall be designed and built with the frequency and voltage excursion equipment if it is the industry standard, readily and commercially available and comes at competitive market prices.
This standard should concentrate on being a relay standard because it is not practical to include equipment limitations (excluding generator frequency and voltage protective relay equipment) that might trip the generating unit or generating plant offline. Just to figure out what the equipment limitations are at a generating plant an entity would have to perform a complete analysis and stability study on the generating plant including all auxiliary systems. If an entity cannot do this within it's organization, it will have to hire a contractor and/or outside consultant to inventory, test, and model the unit/plant. This type of analysis will be expensive and will come without any guarantees from the contractor that all the equipment limitations have been noted or discovered. In addition to the initial testing that a unit/plant will require to meet this standard, an entity will have to perform some type of routine testing and maintenance program in this area to ensure equipment characteristics have not changed enough to become a plant limitation (heat and age changes equipment characteristics). Based on this standard, entities will have to have equipment tested and built to certain specifications that will allow it to ride through a voltage and/or frequency excursion which will increase equipment and maintenance costs and could potentially limit equipment suppliers. One has to wonder if all of this cost will guarantee an increase in BES reliability that makes it worth paying for the work and equipment that will be needed for compliance (with the chance that the plant will still trip offline). In how many past instances has what this standard is trying to protect against been a proven issue? There term "power conversion control equipmen"t is not defined and will allow entities to apply this term to different equipment which may or may not be correct. The SDT should take the time to define it now and not allow a CAN to define it. Measure five (M5) is currently written so that it appears that an entity will have to purchase a Digital Fault Recorder(s) for the unit/plant in order to produce the evidence needed to show a unit tripped offline (i.e. frequency rate of change greater than 2.5 Hz/sec) outside of the "no trip" zone. IMPA does not agree with this philosophy since the cost to purchase and install DFR's can be costly, especially to smaller entities. Why is 5.2 allowed for new units but not existing units? In 5.6, what makes the Mitigation Plan acceptable? Who needs to approve or make the Mitigation Plan acceptable. Where is the Mitigation Plan defined? IMPA believes the word "acceptable" should be removed.
Individual
John
John Bee

Yes
No
The SDT needs to clarify and state that generating units will be able to use testing and verification data developed prior to the standard being approved and going into effect. Please consider adding text specifically stating this to the Standard itself similar to MOD-026 Attachment 1 that provides a “Consideration for Early Compliance” provision. Refer to MOD-026-1 draft revision 2 Section 6, “Consideration for Early Compliance.”
Draft MOD-026-1 R.2.1 requires that the Generator Owner perform verifications subject to include certain information as specified in sub requirements 2.1.1 through 2.1.6. R 2.1.1 requires that the unit model response is matched to the recorded response for a voltage excursion at the “point of interconnection”. For certain generating units the “point of interconnection” is on the high voltage side of the main power transformer (i.e., the switchyard disconnect switch). Because of this, the model would have to consider the impact of the main power transformer, auxiliary transformer, and auxiliary transformer loads all of which are not part of the generator/excitation system model. The Standard should be revised to state the response of interest is at the generator terminals and not at the “point of interconnection.” Typically individual synchronous machines have generator excitation control systems and do not have volt/var control systems. The text “and / or” or “as applicable” should be added to all references to “volt/var model” in the Standard and the associated attachments. With respect to the SDTs response to Exelon’s comment regarding the lack of acceptance criteria (refer to MOD-026-1 Consideration of Comments dated 2-23-12 pp 89-90), the following statements by the SDT need to be more clearly articulated within the body of the Standard. “It should be noted that the standard is written so that the Generator Owner “owns’ the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model’s predicted response.” The current draft (draft 3) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not “usable”, if there are technical concerns with the verification documentation, or if the model response did not match an actual event. This written response is to contain either plans for performing model verification, model changes or a technical basis for maintaining the current model. It appears from the comments of the SDT (see question 3 above) that the Generator Owner has final say on the model; however, if the opinion of the Transmission Planner differs from that of the Generator Owner there is the potential for a disagreement between the two entities. Given the potential for a dispute to occur and the lack of an “acceptance criteria” the SDT should consider adding in a provision for dispute resolution between the parties or clearly delineate that the GO has the final say.
No
The Frequency/Voltage Excursions should be limited to those listed in the standard, this should be explicitly stated in the requirement. 60 calendar days is an unreasonable amount of time to perform a study of this magnitude, suggest increasing the amount of time perform this study.
No
: It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the “no trip zone.” If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions.
The Off Normal Frequency Capability Curve should consist of separate tables for each Interconnect to make it easier to read. Exelon still feels that Footnote 1 belongs in the Applicability section of the standard. Suggest that the Applicability section be revised to state “GO shall set applicable protective relaying so as not to impact R1.1, R1.2, R1.3, R1.5 unless exempted by non-protection system equipment limitations per the exclusion criteria. It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the “no trip

zone." If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2007-09 Generator Verification

MOD-026-1 and PRC-024-1

The Generator Verification Drafting Team thanks all commenters who submitted comments on the proposed revisions to MOD-026-1 and PRC-024-1. These standards were posted for a 30-day public comment period from February 29, 2012 through March 29, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 53 sets of comments, including comments from approximately 127 different people from approximately 88 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at Mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The GVSDT has added an additional condition to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service. Do you agree with this concept? If not, please explain in the comment area below. 13
2. The GVSDT has provided guidance on the periodicity aspects of Attachment 1 (see above). Do you agree? If not, please explain in the comment area below. 20
3. Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. Though not a change from the previous posting, the SDT emphasizes for clarity that only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) or units that are already registered (for reasons such as being required to by their RRO) are subject to Requirement R5. Do you agree with the revisions to applicability and to Requirement R5? If not, please explain in the comment area below. 29
4 To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions. Do you agree with this revisions? If not, please explain in the comment area below.51
5. Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-026-1? 58
6. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language. 129
7. Requirement R5 requires a Generator Owner’s new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. Please provide along with your comment, what you believe the timeframe is needed to implement this requirement. 148

8. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-024-1? 178

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Chantel Haswell	FPL Group, Inc.	NPCC	5
9.	David Kiguel	Hydro One Networks, Inc.	NPCC	1
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11. Randy MacDonald	New York State Reliability Council, LLC	NPCC	9
12. Bruce Metruck	New York Independent System Operator	NPCC	6
13. Lee Pedowicz	Hydro-Quebec TransEnergie	NPCC	10
14. Robert Pellegrini	Consolidated Edison Co. of New York, Inc.	NPCC	1
15. Wayne Sipperly	Northeast Power Coordinating Council	NPCC	5
16. Si-Truc Phan	Dominion Resources Services, Inc.	NPCC	1
17. David Ramkalawan	Consolidated Edison Co. of New York, Inc.	NPCC	5
18. Brian Robinson	FPL Group, Inc.	NPCC	8
19. Saurabh Saksena	Hydro One Networks, Inc.	NPCC	1
20. Michael Schiavone	Northeast Utilities	NPCC	1
21. Tina Teng	New York State Reliability Council, LLC	NPCC	2
22. Donald Weaver	New York Independent System Operator	NPCC	2
23. Ben Wu	Hydro-Quebec TransEnergie	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Don Jones	Texas Reliability Entity										X

Additional Member	Additional Organization	Region	Segment Selection
1. Curtis Crews	Texas Reliability Entity	ERCOT	10
2. David Penney	Texas Reliability Entity	ERCOT	10

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Jonathan Hayes	Southwest Power Pool	SPP	2
2. Robert Rhodes	Southwest Power Pool	SPP	2
3. Valerie Pinamonti	AEP	SPP	1, 3, 5
4. Michelle Corely	CLECO	SPP	1, 3, 5
5. Mahmood Safi	OPPD	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Jason Marshall	ACES Power Marketing Standards Collaborators	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. James Jones	Arizona Electric Power Cooperative	WECC	4, 5
2. James Jones	Southwest Transmission Cooperative, Inc.	WECC	1
3. Lindsay Shepard	Sunflower Electric Power Corporation	SPP	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4. Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5										
5. Mike Brytowski	Great River Energy	MRO	1, 3, 5										
5.	Group	David Thorne	Pepco Holdings Inc. & Affiliates	X		X							
Additional Member	Additional Organization	Region	Segment Selection										
1. Carl Kinsley	Pepco Holdings Inc.	RFC	1, 3										
6.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4										
2. Jim Howard	Lakeland Electric	FRCC	3										
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3										
4. Lynne Mila	City of Clewiston	FRCC	3										
5. Joe Stonecipher	Beaches Energy Services	FRCC	1										
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4										
7. Randy Hahn	Ocala Utiilty Services	FRCC	3										
7.	Group	Tom Flynn	Puget Sound Energy	X		X		X					
Additional Member	Additional Organization	Region	Segment Selection										
1. Denise Lietz	Puget Sound Energy	WECC	1										
2. Erin Apperson	Puget Sound Energy	WECC	3										
8.	Group	Mike Garton	Dominion	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Michael Gildea	Dominion Resources Services, Inc.	MRO	5										
2. Louis Slade	Dominion Resources Services, Inc.	RFC	4, 5										
3. Connie Lowe	Dominion Resources Services, Inc.	NPCC	4, 5										
4. Michael Crowley	Virginia Electric and Power Company	SERC	1, 3										
9.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				X
Additional Member	Additional Organization	Region	Segment Selection										
1. MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6										
2. CHUCK LAWRENCE	ATC	MRO	1										
3. TOM WEBB	WPS	MRO	3, 4, 5, 6										
4. JODI JENSON	WAPA	MRO	1, 6										

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

5. KEN GOLDSMITH	ALTW	MRO	4
6. ALICE IRELAND	XCEL (NSP)	MRO	1, 3, 5, 6
7. DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8. ERIC RUSKAMP	LES	MRO	1, 3, 5
9. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10. SCOTT NICKELS	RPU	MRO	4
11. TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12. MARIE KNOX	MISO	MRO	2
13. LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14. SCOTT BOS	MPW	MRO	1, 3, 5, 6
15. TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17. THERESA ALLARD	MPC	MRO	1, 3, 5, 6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jose Landeros	IID	WECC	1, 3, 4, 5, 6
2. Cathy Bretz	IID	WECC	1, 3, 4, 5, 6
3. Christopher Reyes	IID	WECC	1, 3, 4, 5, 6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Annette M. Bannon	PPL Electric Utilities and PPL Supply NERC Registered Organizations	X				X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2. Annette Bannon	PPL Generation, LLC on Behalf of its NERC Registered	RFC	5
4. Mark Heimbach	PPL EnergyPlus, LLC	MRO	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Steve Rueckert	Western Electricity Coordinating Council										X

No additional members listed.

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck	Matthews	WECC	1
2. Rebecca	Berdahl	WECC	

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Individual	David Youngblood	Luminant Power					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
16.	Individual	David Thompson	Tennessee Valley Authority GO/GOP	X		X		X	X				
17.	Individual	Janet Smith, Supervisor Regulatory Compliance	Arizona Public Service Company	X		X		X	X				
18.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
19.	Individual	Antonio Grayson	Southern Company	X		X		X					
20.	Individual	Frederick R Plett	Massachusetts Attorney General								X		
21.	Individual	Dan Roethemeyer	Dynegy					X					
22.	Individual	Matthew Pacobit	AECI					X					
23.	Individual	John Seelke	PSEG	X		X		X	X				
24.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
25.	Individual	Dale Fredricksen	We Energies			X	X	X					
26.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
27.	Individual	Michael Falvo	Independent Electricity System Operator		X								
28.	Individual	Kathleen Goodman	ISO New England Inc		X								
29.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
30.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
31.	Individual	Anthony Jablonski	ReliabilityFirst										X
32.	Individual	Thad Ness	American Electric Power	X		X		X	X				
33.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
34.	Individual	Brad Jones	Luminant Energy						X				
35.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
36.	Individual	Richard Vine	California Independent System Operator		X								
37.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
38.	Individual	Daniel J Hansen	GenOn Energy					X					
39.	Individual	Patrick Brown	Essential Power, LLC					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Larry Raczkowski	FirstEnergy Corp	X		X	X	X	X				
42.	Individual	Mark B Thompson	Alberta Electric System Operator		X								
43.	Individual	Jeanie Doty	Austin Energy	X		X	X	X					
44.	Individual	Randall McCamish	City of Vero Beach	X		X							
45.	Individual	Christine Hasha	ERCOT		X								
46.	Individual	Ed Davis	Entergy Services	X		X		X	X				
47.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
48.	Individual	Ken Wofford	Georgia Transmission Corporation	X									
49.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
50.	Individual	Russell A. Noble	Cowltiz PUD			X	X	X					
51.	Individual	Michael Goggin	American Wind Energy Association								X		
52.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
53.	Individual	John Bee	Exelon Corp.	X		X		X					

MOD-026 Overall Summary Consideration: The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

The vast majority of the industry commenters agreed with the concept of specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. The GVSDT received comments regarding other aspects of the standard. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1. Also, some commenters were concerned that Table 1 inferred that plants with complex reactive coordination controllers may be unduly exempted from being applicable. The SDT clarified that for plants that include devices that provide dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants) these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that do not contain any closed loop voltage regulation function. The SDT added some clarifying verbiage to row 6 Table 1 that ultimately references Footnote 1 in the standard.

Most of industry commented that they agreed with the guidance provided by the SDT on the periodicity aspects of Attachment 1. Unfortunately, many commenters did not correlate the guidance on the periodicity aspects of Attachment 1 to the examples "above" in the Background section of the Comment Form. Please see the Summary Consideration section for Question 5 as there were several comments regarding the periodicity examples.

The majority of the industry commenters agreed with specifying the capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, many of the commenters pointed out that neither the net or gross calculation was specified in the standard and suggested the SDT use the "net" calculation. As such, the SDT has revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Finally, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 7) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 4)

The following modifications to the draft standard were incorporated as a result of industry comments:

1. **A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**

2. The SDT has refined verbiage and the format in the standard applicability and Requirement R2, Part 2.1 to clarify the use of individual and aggregate models for plants.
3. The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.
4. The SDT replaced "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard. This revision was made in Section 4.2.4 under Applicability, in Requirement R5, and in Attachment 1.
5. The SDT revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.
6. Requirement R2, Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.
7. The SDT has refined section 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability.
8. The SDT has re-formatted the Periodicity Table (Attachment 1) to make it clearer that the table is included.
9. Revised the Periodicity Table (Attachment 1) extensively for clarity, including removing specificity regarding when the voltage excursion used for model verification had to be captured. This resulted in a modification of the required times for re-verifying the model for exception (Requirements R3 and R4) type activities.
10. The SDT made corrections to VSL verbiage (less than or equal to with respect to days late) and replaced Planning Coordinator with Transmission Planner.
11. In Requirement R5, in describing checking the actual equipment to determine if updated model data could be obtained, the expression "walk down" was replaced by "on-site review" of the equipment
12. The term "inertia" in sub part 2.1.3. was modified to "total rotational inertia" as some industry commenters expressed concern that reference to "inertia" only would lead to submittal of an inertia constant reflective only of the generator, as opposed to all of the mass attached to the shaft.
13. In Requirement R2, Part2.1.1, the specific reference to point of interconnection has been removed. The location where the unit's response is measured is left to the model verification entity.

14. **The second bullet in Requirement R1 has been modified to be the same style and sentence structure used in the first bullet of R1.**
15. **The SDT has removed the term “generating plant / Facility” and replaced it with “individual generating plant consisting of multiple generation units that are directly connected at a common BES bus” at the top level of the Facilities section (A4.2).**
16. **The SDT modified the phrase "generator excitation control system and plant volt/var control functions” to “generator excitation control system or plant volt/var control functions” to recognize that the use of the phrase “or” is technically correct the vast majority of the time.**

1. **The GVSDT has added an additional condition to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service. Do you agree with this concept? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of the industry commenters agreed with the concept of specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function.

Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1.

Also, some commenters were concerned that Table 1 inferred that plants with complex reactive coordination controllers may be unduly exempted from being applicable. The SDT clarified that for plants that include devices that provide dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants), these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that did not contain any closed loop voltage regulation function. The SDT added some clarifying verbiage to the appropriate row in Table 1 (referencing back to Footnote 1).

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Negative	Requirement R6: The criteria for deeming the model data provided by the GO acceptable may not be achievable. The difficulty to meet this requirement may not be due to inaccuracy or errors in the verification process, but simply due to the poor design of the devices to be verified. The requirement can deem a GO non-compliant despite its goodwill and effort to provide the most accurate verification data. **Requirement R6 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the**

Organization	Yes or No	Question 1 Comment
		Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement 3, the GO is only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, the GO will be in compliance. The revised Attachment 1 is confusing, in 2 aspects: a. It is not clear whether or not the 3 by 12 table part is part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with. **The table is included in Attachment 1. The format has been modified to emphasize that the table is included in Attachment 1.** b. Question 2 in the Comment Form suggests that guidance is provided on the periodicity aspects of Attachment 1. It is not clear whether the content in the 3x12 table is meant to be guidance. If so, it needs to be clearly stated so that it does not need to be complied with. If the content is not guidance, then it is not clear where and what is the guidance that the SDT is referring to. **The "guidance" that was referred in question 2 of the Comment Form was referencing the graphical examples in the MOD-026 Background Information portion of the Comment Form (specifically reference Periodicity Example 1, Periodicity Example 2, and Periodicity Example 3).**
Response: Thank you for your comment. Please see responses above.		
Northeast Power Coordinating Council	No	While some plants may not have excitation systems, they can have complex reactive coordination controllers whose settings and functions should be tested and verified.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants), these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that did not contain any closed loop voltage regulation function (and therefore nothing to model or validate in the scope of this standard). **To clarify this point, a reference to Footnote 1 in Row 6 of the Periodicity Table has been made for clarification of what constitutes a closed loop function.**		
Massachusetts Attorney General	No	a particular unit may not pose much problem to a system but an aggregation may. One would think that over a threshold # of MW that active close loop regulation functions should be present.
Response: Thank you for your comment. The scope of the draft standard is to ensure that excitation control system and plant volt/var control function models and the model parameters used in dynamic simulations accurately represent the generator excitation control system and plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability. Requirements specifying thresholds requiring active closed loop regulation functions are outside the scope of the standard as stated in the SAR.		
Manitoba Hydro	No	Manitoba Hydro agrees with the concept for manually switched capacitor banks but disagrees for automatic capacitor banks. A model should be required for automatic capacitor banks.
Response: Thank you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, and perhaps automatically controlled capacitors commonly found in Renewable Plants), these devices should be included in the model and should be validated. If the automatically controlled (mechanically switched) capacitor bank is in whole or a part of		

Organization	Yes or No	Question 1 Comment
the primary dynamic volt/var response of the plant, it should be modeled and validated. Both PSS/e and PSLF have standard library models to represent automatically switched capacitor banks (SWSHNT in PSS/e and MSC1 in PSLF). Ultimately, the local interconnection requirements should be used to determine if the automatically controlled capacitor banks are a primary means for dynamic volt/var regulation within any particular application. Based on review of a plant's application requirements, the testing /validation entity should determine if the automatic capacitor bank should be validated.		
ISO New England Inc	No	While some plants may not have excitation systems, per se, they can have complex reactive coordination controllers, whose settings and functions should be tested and verified.
Response: Thank you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants), these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that do not contain any closed loop voltage regulation function (and therefore nothing to model or validate in the scope of this standard). **To clarify this point, a reference to Footnote 1 in Row 6 of the Periodicity Table has been made for clarification of what constitutes a closed loop function.**		
Southern Company	Yes	Yes we agree with this concept. It is not practical, and there is no benefit to reliability, to require validation for units which do not include an active closed-loop voltage regulator function.
Response: The SDT thanks you for your comment.		
We Energies	Yes	Add more explicit detail to the Table to indicate that the exemption may apply to some wind farms, solar resources, etc.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. To clarify this point, a reference to footnote 1 in Row 6 of the Periodicity Table has been made for clarification of what constitutes a closed loop function to determine if, in part, an exemption is allowable for a particular plant.		
Ingleside Cogeneration LP	Yes	We agree that there is no useful purpose served by requiring a GO to validate voltage performance on those generators where an active voltage regulator is not used. The modeling of passive capacitor and reactor banks has been established for many years and does not likely need any improvement.
Response: The SDT thanks you for your comment.		
Los Angeles Department of Water and Power	Yes	LADWP agrees with this concept since no feedback signal is available (in an open loop control) to regulate against for Setpoint (Reference) control.
Response: The SDT thanks you for your comment.		
Texas Reliability Entity	Yes	
Southwest Power Pool Standards Development Team	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Puget Sound Energy	Yes	
MRO NSRF	Yes	

Organization	Yes or No	Question 1 Comment
Imperial Irrigation District (IID)	Yes	
PPL Electric Utilities and PPL Supply NERC Registered Organizations	Yes	
Luminant Power	Yes	
Tennessee Valley Authority GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Dynegy	Yes	
AECI	Yes	
PSEG	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
American Transmission Company, LLC	Yes	
American Electric Power	Yes	
Luminant Energy	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
Ameren	Yes	
FirstEnergy Corp	Yes	
Austin Energy	Yes	
Southern California Edison Company	Yes	
Georgia Transmission Corporation	Yes	
Cowltiz PUD	Yes	
American Wind Energy Association	Yes	
Exelon Corp	Yes	
Pepco Holdings Inc. & Affiliates		No comment
Indiana Municipal Power Agency		no comment

2. **The GVSDT has provided guidance on the periodicity aspects of Attachment 1 (see above). Do you agree? If not, please explain in the comment area below.**

Summary Consideration: Most of industry commented that they agreed with the guidance provided by the SDT on the periodicity aspects of Attachment 1.

Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1. Unfortunately, many commenters did not correlate the guidance on the periodicity aspects of Attachment 1 to the examples "above" in the Background section of the Comment Form. Please see the Summary Consideration section for Question 5 as there were several comments regarding the periodicity examples.

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	Negative	Requirement R6: The criteria for deeming the model data provided by the GO acceptable may not be achievable. The difficulty to meet this requirement may not be due to inaccuracy or errors in the verification process, but simply due to the poor design of the devices to be verified. The requirement can deem a GO non-compliant despite its goodwill and effort to provide the most accurate verification data. The revised Attachment 1 is confusing, in 2 aspects: **Requirement R6 is intended for the Transmission Planner. If the Transmission Planner deems that the model is not useable, then the Generator Owner has to reply to the Transmission Planner's written comments. The Generator Owner's obligation is to respond to the Transmission Planners written comments, therefore, the only way the Generator Owner could be found non-compliant is if he did not respond at all.** a. It is not clear whether or not the 3 by 12 table part is part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with.

Organization	Yes or No	Question 2 Comment
		b. Question 2 in the Comment Form suggests that guidance is provided on the periodicity aspects of Attachment 1. It is not clear whether the content in the 3x12 table is meant to be guidance. If so, it needs to be clearly stated so that it does not need to be complied with. If the content is not guidance, then it is not clear where and what is the guidance that the SDT is referring to. **The intent is that Attachment 1 includes the table. Based on your comment, Attachment 1 has been re-formatted in such a way that it is clear that the table is included in Attachment 1. The "guidance" that was referred in question 2 of the Comment Form was referencing the graphical examples in the MOD-026 Background Information portion of the Comment Form (specifically reference Periodicity Example 1, Periodicity Example 2, and Periodicity Example 3). Given that Requirement R2 requires model verification per the periodicity specified in Attachment 1, and Attachment 1 contains the table, then the table does dictate required model verification periodicity.**
Response: Thank you for your comment. Please see responses above.		
Independent Electricity System Operator	No	Attachment 1 is confusing, in 2 aspects: a. Attachment 1 starts off with a heading and a blue-shaded page in which the verification periodicity requirements are clearly stated. It is not clear whether or not the 3 by 12 table that follows is a part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with. b. This question (Q2) suggests that guidance is provided on the periodicity aspects of Attachment 1. Is the content in the 3x12 table meant to be guidance? If so, it should be clearly stated so that it does not need to be complied with. If not, where and what is the guidance that the SDT refers to?

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment. The intent is that Attachment 1 includes the table. Based on your comment, Attachment 1 has been re-formatted in such a way that it is clear that the table is included in Attachment 1. The “guidance” that was referred in question 2 of the Comment Form was referencing the graphical examples in the MOD-026 Background Information portion of the Comment Form (specifically reference Periodicity Example 1, Periodicity Example 2, and Periodicity Example 3). Given that Requirement R2 requires model verification per the periodicity specified in Attachment 1, and Attachment 1 contains the table, then the table does dictate required model verification periodicity.</td></tr>
<tr><td>American Electric Power</td><td>No</td><td>The tiered approach of MOD-026 Attachment 1 are both unorganized and more complex than necessary, and is confusing as a result. The same approach could be communicated in a more succinct format. In addition, there is content within the attachment that is not mentioned anywhere else in the standard, such as the initial verification of new units and dealing with equivalent units at the same physical location.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The intent of the Periodicity Table is to specify periodicity details which would not be considered reliability related requirements. However, the SDT is always open to specific suggestions regarding the formatting of the standard and supporting attachments.</td></tr>
<tr><td>Ameren</td><td>No</td><td>The comments and guidance of the GVSDT are greatly appreciated. However, we have a concern/question, how would the periodic verification/testing requirements for MOD-026 would align with other such requirements in place for MOD-024, MOD-025 and with reporting requirements of MOD-012 and MOD-013?

We would like the GVSDT to consider a well-coordinated periodic verification and reporting needs for all such requirements to provide the GO flexibility to schedule their tasks to meet these requirements without undue burden to take facility out of service at different times.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. MOD-024 and MOD-025 have now been combined. The verification of steady state MW and MVAR capabilities would be accomplished by test which is distinctly different than the activities required for verification of excitation control systems. Also, the verification of steady state MW and MVAR capabilities would be accomplished without</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
taking the unit out of service. Personnel involved in steady state MW and MVAR capabilities will almost certainly be different than personnel involved in the verification of excitation control systems. Also, the verification of excitation control systems per the current draft of MOD-026 will almost always be ten years, whereas the periodicity of steady state MW and MVAR capabilities per the current draft of MOD-025 is only five years. MOD-012 and MOD-013 are simply data submittal standards as opposed to data verification standards.		
Austin Energy	No	Per R1. the TP should provide periodicity.
Response: Thank you for your comment. The SDT believes that a national standard for dynamic model verification has to include periodicity to ensure that excitation control system models used in studies to set BES limits are of sufficient accuracy.		
Exelon Corp.	No	The SDT needs to clarify and state that generating units will be able to use testing and verification data developed prior to the standard being approved and going into effect. Please consider adding text specifically stating this to the Standard itself similar to MOD-026 Attachment 1 that provides a “Consideration for Early Compliance” provision. Refer to MOD-026-1 draft revision 2 Section 6, “Consideration for Early Compliance.
Response: Thank you for your comment. The SDT re-formatted Attachment 1 in part to emphasize activities that would result in an entity being able to take credit for model verification prior to the effective data, as long as that activity either met the requirements of the standard or was performed compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification (reference Note 2 at the end of the table).		
ACES Power Marketing Standards Collaborators	Yes	The examples included in the Unofficial Comment Form are helpful in understanding the periodicity requirements associated with verifying the excitatation and volt/VAr control systems model and should be moved into an attachment in the standard. The standard is not as clear as the examples and the periodicities could be misinterpreted in the future without examples.
Response: Thank you for your comment. The examples provided were for clarification, and the SDT does not believe that all		

Organization	Yes or No	Question 2 Comment
possible scenarios are considered. The SDT does not believe the examples are appropriate for inclusion in the standard itself.		
Southern Company	Yes	A periodicity of ten years between model verifications when there are no special circumstances is appropriate. What is the basis for a ten year re-verification for units where no changes to the excitation system have occurred? A ten year verification basis for an non-modified digital excitation system does not seem to be justified.
Response: Thank you for your comment. The SDT believes that the 10 year periodicity is appropriate and has received industry support for this concept, specifically as a result of the first posting. Digital excitation systems settings can be modified, and there are other components in the closed loop system that can degrade with heat and stress over time (SCRs, any discrete electronic component, etc).		
PSEG	Yes	The examples in the unofficial comment form should be incorporated into an attachment to the standard for ease of reference.
Response: Thank you for your comment. The examples provided were for clarification, and the SDT does not believe that all possible scenarios are considered. The SDT does not believe the examples are appropriate for inclusion in the standard itself.		
Manitoba Hydro	Yes	The implementation plans/effective dates for the standards MOD-025 , MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.
Response: Thank you for your comment. MOD-024 and MOD-025 have now been combined. The verification of steady state MW and MVAR capabilities would be accomplished by test which is distinctly different than the activities required for verification of excitation control systems. Also, the verification of steady state MW and MVAR capabilities would be accomplished without taking the unit out of service. Personnel involved in steady state MW and MVAR capabilities will almost certainly be different than personnel involved in the verification of excitation control systems. Also, the verification of excitation control systems per the current draft of MOD-026 will almost always be ten years, whereas the periodicity of steady state MW and MVAR capabilities		

Organization	Yes or No	Question 2 Comment
per the current draft of MOD-025 is only five years. Also, the effective and implementation dates for the current drafts of MOD-026 and MOD-027 (dynamic model verification standards) are effectively the same.		
Ingleside Cogeneration LP	Yes	We support the effort by all project teams to clearly define the implementation and subsequent periodic evaluation time frames - as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC's Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-026-1, we believe that the proposed intervals are sufficient to perform the voltage performance model validations; however they are initiated.
Response: The SDT thanks you for your comment.		
GenOn Energy	Yes	In Attachment 1, the title "Consideration for Early Compliance" should be changed to "Compliance for Prior Verification"
Response: Thank you for your comment. The SDT re-formatted Attachment 1 in part to emphasize activities that would result in an entity being able to take credit for model verification prior to the effective data, as long as that activity either met the requirements of the standard or was performed compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.		
Los Angeles Department of Water and Power	Yes	LADWP agrees with the guidance.
Northeast Power Coordinating Council	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 2 Comment
Southwest Power Pool Standards Development Team	Yes	
Puget Sound Energy	Yes	
MRO NSRF	Yes	
Imperial Irrigation District (IID)	Yes	
PPL Electric Utilities and PPL Supply NERC Registered Organizations	Yes	
Luminant Power	Yes	
Tennessee Valley Authority GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Massachusetts Attorney General	Yes	
Dynegy	Yes	
AECI	Yes	
ISO New England Inc	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
American Transmission Company, LLC	Yes	
Luminant Energy	Yes	
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Southern California Edison Company	Yes	
Georgia Transmission Corporation	Yes	
Cowltiz PUD	Yes	
American Wind Energy Association	Yes	
Pepco Holdings Inc. & Affiliates		No comment
Indiana Municipal Power		no comment

Organization	Yes or No	Question 2 Comment
Agency		

3. **Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. Though not a change from the previous posting, the SDT emphasizes for clarity that only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) or units that are already registered (for reasons such as being required to by their RRO) are subject to Requirement R5. Do you agree with the revisions to applicability and to Requirement R5? If not, please explain in the comment area below.**

Summary Consideration:

1) **The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard**

   Additionally, though not specifically related to the SDT's question, the following modifications were made to the standard based on industry responses in this question:

2) **A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
3) **The SDT has refined verbiage and the format in the standard applicability and Requirement R2, Part 2.1 to clarify the use of individual and aggregate models for plants.**
4) **The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.**
5) **The SDT replaced "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.**

Organization	Yes or No	Question 3 Comment
Beaches Energy Services, City	Negative	The applicability refers to the "bulk power system", e.g., "4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to

Organization	Yes or No	Question 3 Comment
of Green Cove Springs		the bulk power system". The term "bulk-power system" should not be used in the standards as it is ambiguous and should be replaced with "Bulk Electric System" We do not understand how the Applicability of 4.2.1.2 means. We suggest making the language clearer. **We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. **A staged test to obtain data to verify excitation control system models does not involve an actual BES voltage excursion. A staged test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.** R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. **Changes in operating mode (auto/manual, PSS on/off, etc.) do not trigger the need to provide a revised model or re-verification as described in Requirement R4. The following sentence has been added to Footnote 5 to clarify the intent: "Changes in settings that occur due to changes in operating mode do not apply to Requirement R4".** R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualified? **"Technical justification" is defined by the TP as demonstrating that the simulated**

Organization	Yes or No	Question 3 Comment
		unit or plant response does not match the measured unit or plant response.
Response: The GVSDT thanks you for your comment. Please see responses above.		
PacifiCorp	Negative	1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." **We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **The SDT has refined section 4.2.2 of the Facilities section under Applicability and Part 2.1 to clarify the use of individual and aggregate models for plants.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating

Organization	Yes or No	Question 3 Comment
		plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6." **The SDT moved the language that was in Part 2.2 to Part 2.1, and modified the language to make it clear that the use of individual or aggregate models for units less than 20 MVA (gross nameplate capability) is left to the discretion of the entity performing the model verification.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Public Utility District No. 1 of Lewis County	Negative	As a generator owner of a small plant we do not have the experience or expertise in modeling therefore all model and explanation of model would come from a testing and consultant firm. There is a high cost for a small plant to obtain this test data. Standard should only apply to 100MVA generators as in the Eastern and Quebec interchange. **The individual unit and aggregate plant ratings used in the applicability section were carefully derived for each Interconnection to capture validation of approximately 80% of the total installed base in that region. The selection of these applicability requirements intend to strike the most reasonable balance between managing the costs to perform tests and validation vs. ultimately assuring that the reliability of the Bulk System is not compromised due to poor models.** If we run the model testing and the Transmission Planner does not like the modeling, then we have to run the model testing again? More cost and no benefit to us or the system. **There is no requirement or measurement in the standard where the planning authority accepts or denies quality of the match between the model and field tests. The SDT strongly believes that the judgment of an “adequate model” is best**

Organization	Yes or No	Question 3 Comment
		left to the Generator Owner and their testing and validation entity. In the SDT's experience, the adequacy of the validated models is not questioned by planning authorities. However, per Requirement R6, questions regarding the usability of these models (i.e. initialization, numerical stability, etc) may exist and would need to be addressed. The Transmission Planner should select plant and units that are critical to system operation, not one size fits all as stated in the standard. **The SDT was unable to identify a methodology that is consistently applicable to all regions and interconnections regarding "critical system components". Therefore, MVA thresholds are the only common means to be used as a proxy for defining "critical system components".**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Northeast Power Coordinating Council	No	Footnote 4 in the Applicability Section implies comparing simulated unit or plant responses to dynamic system events. Verifying the model only after an event as is called for in footnote 4 is completely counter to increasing system reliability. Analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. The Applicability Section needs further revision because by requiring only generators above 100 MVA with unit capacity factors above 5 % to test excludes an unacceptably large amount of installed generation. For example, about 30% of the installed generation in New England would not therefore, require model validation. This is an excessively large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being most stressed and reliable operation is being most challenged. If the objective of the Standard is to develop the right models for dynamic simulations, models must include high and low capacity factor units, transient and

Organization	Yes or No	Question 3 Comment
		long term models, etc. for all network conditions. A model for the generators and associated equipment is supplied in accordance with MOD-012. The accuracy of such models may be limited and a higher percentage of generator validation is required. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 (footnote 2 in the current draft) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this**

Organization	Yes or No	Question 3 Comment
		proposed standard. **Also, the SDT does recognize that Regional variances can be considered if a Region desires to include additional unit MVA in this standard.** Footnote 4 should be changed to allow verification of generator models not required under the Applicability Section to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical. Requirement R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate. What is meant by a “technically justified request” from the PC? R5 refers to the Planning coordinator, yet the Planning Coordinator is not listed in the Applicability Section of MOD-026. MOD-026 deviates from the NERC Functional Model Version 5 in that MOD-026 R5 has the Generator Owner communicating with the Planning Coordinator. T The NERC Functional Model stipulates that the Transmission Planner communicates with the GO/GOP. The PC then collects the data from the TPs in its area, and from adjacent PCs. The Standard should be consistent with the NERC Functional Model. **Thank you for your comment. The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard – notably excluding units and plants that do not meet the thresholds of the registry criteria. The SDT also has replaced references to the Planning Coordinator with the Transmission Planner, in large part due to the reasons you have stated.** **Also, the SDT does recognize that Regional variances can be considered if a Region desires to include units based on other criteria to this standard.**

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. Please see responses above.		
ACES Power Marketing Standards Collaborators	No	We appreciate the drafting team explaining their intent that only those units that meet the Compliance Registry Criteria are included. However, the language in the standard does not communicate this and the Statement of Compliance Registry Criteria has some ambiguous criteria that makes it unclear if a generator is applicable which is further discussed below. First, applicability section 4.2.4 of the standard discusses "any registered technically justified unit". Units are not registered. Entities (i.e. companies) are registered. A Generation Owner certainly becomes registered by the application of the Compliance Registry Criteria to its generating fleet but there is no publicly available list to which the applicable entities can refer to identify if a generating unit met the Compliance Registry Criteria. Thus, how would a Planning Coordinator know they could make a request? **The SDT has refined section 4.2.4 of the standard applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.** Second, the Compliance Registry Criteria includes units smaller than the 20 MVA unit threshold and 75 MVA plant threshold referenced by the drafting team. Blackstart Resources are included in the Compliance Registry Criteria and there is a statement that any generator that is material to the reliability of the Bulk Power System can be included. Blackstart Resources are usually very small and most likely do not meet the 5% capacity factor requirement established in other areas of the applicability section. **The SDT did not intend to treat black start units differently from any other units.** We are guessing the drafting team did not intend to include these Blackstart units or any others units that don't meet the 20 MVA unit threshold and 75 MVA plant threshold established in Criteria III(c).1 and III(c).2 with the Appendix 5B - Statement of Compliance Registry Criteria.

Organization	Yes or No	Question 3 Comment
		For clarity, the drafting team should modify applicability section 4.2.4 accordingly to eliminate units that are not intended to be included. Third, we disagree with the statement in the Background Information section of the comment form that the applicability section would have to explicitly identify units below the Compliance Registry Criteria. **The SDT has refined section 4.2.4 of the standard applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.** Because the standards applicability is not specifically limited to the Bulk Electric System, the statement in Requirement R5 that "any/plant not included in the Applicability" means that any unit that is considered part of the Bulk Power System could be requested by the Planning Coordinator. NERC enforces standards to the Bulk Power System which could include units below the Compliance Registry Criteria. They have made this clear in response to comments on CAN-0016 that the standards are enforced to the Bulk Power System. **The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard. Also the SDT has replaced the term "BPS" with the defined term "BES".** They stated clearly "According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." While the Bulk Power System has never been clearly defined, we know that it is broader than the Bulk Electric System and could certainly include units below the Compliance Registry Criteria. One solution to more fully implement the expressed intent of the drafting team would be to limit the applicability section to the Bulk Electric System. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**

Organization	Yes or No	Question 3 Comment
		Another would be to modify “any unit/plant not included in the Applicability” in Requirement R5 to “any unit/plant on the Bulk Electric System and not included in the Applicability”. While the question posed by the drafting team here indicates that their intent was for the Planning Coordinator’s technical justification to indicate that the actual unit response does not match the simulated response, there is nothing in the standard or requirement that indicates this intent. In fact, it only states the request from the Planning Coordinator must be technically justified. **The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.** We suggest the drafting team modify Requirement R5 to make it clearer the actual system response does not match simulated response. **The clarification for technical justification from Transmission Planner that actual unit response does not match simulated response is included in the referenced Footnote 2.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
MRO NSRF	No	It is suggested the following modification to R5 will more clearly mirror the SDT intent as depicted in the question: “...any unit/plant meeting the Registry Criteria not included in the Applicability that includes one of the following...”
Response: Thanks you for your comment. The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meets NERC registry criteria is potentially in the scope of the standard.		

Organization	Yes or No	Question 3 Comment
PPL Electric Utilities and PPL Supply NERC Registered Organizations	No	The term “standby” in footnote 2 on p.2 bears definition. Is 5% capacity factor the criterion to be used in establishing standby status? If so, it would be best to make this standard entirely unit-based, eliminating all references to plants.
Response: Thank you for your comment. The SDT decided to remove Footnote 2 as the term did not provide clarity to industry as was hoped.		
Massachusetts Attorney General	No	I am concerned about units that may be individually less than 20 MVA but collectively could be much larger - wind farms.
Response: Thank you for your comment. The applicability and Part 2.1 was refined to clarify the use of individual and aggregate models for plants. With this change in the applicability, the SDT believes that this has been addressed, since the objective has always been to validate models for units or plants larger than a certain threshold (different for each interconnection).		
AECI	No	I believe that the threshold of 20 MVA is too low. I would recommend a threshold of a (> 75 MVA)
Response: Thank you for your comment. The applicability was refined to clarify the use of individual and aggregate models for plants. With this change in the applicability, the SDT believes that this has been addressed, since the objective has always been to validate models for units or plants larger than a certain threshold. In other words, validation for small units are only required when these units are part of a plant with total output above the threshold for the given interconnection (75 MVA for ERCOT and WECC and 100 MVA for the Eastern Interconnection).		
Consolidated Edison Co. of NY, Inc.	No	Requirement 5: o R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate.

Organization	Yes or No	Question 3 Comment
		The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard. o It is not clear what constitutes a “technically justified request” from the PC. **The technical justification for a request is described in footnote 2 of the current draft of the standard.** o Refers to Planning Coordinator, but PC is not listed in Applicability section of MOD-026. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard and to conform to NERC functional model.** o Further, under NERC Functional Model Version 5 the Transmission Planner communicates with the GO/GOP. The PC collects data from the TP’s in its area and from adjacent PC’s. See NERC Functional Model Version 5. The standards should conform to the NERC Functional Model. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard and to conform to NERC functional model.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
We Energies	No	We strongly oppose this Requirement as unnecessary to the reliability of the BES. Requirement R5 should be removed from the draft Standard. Either the standard is applicable to a generating unit, or it is not. A generating unit that is not covered in the Applicability section should be exempt from the requirements of this standard unless the standard is revised under the approved

Organization	Yes or No	Question 3 Comment
		standards development process. The SDT's assurances to the contrary are not sufficient. This requirement will allow the possibility of sweeping more generators into the requirements than is necessary.
Response: Thanks you for your comment. The SDT has refined section 4.2.4 of the Facilities section under Applicability to clarify that any technically justified unit that meet NERC registry criteria is potentially in the scope of the standard. Also the SDT has replaced the term "BPS" with the defined term "BES".		
ISO New England Inc	No	No, Footnote 4 in the Applicability Section implies comparing simulated unit or plant response to a dynamic system event. This is not acceptable, verifying the model only after an event as called for is completely counter to increasing system reliability. In addition, analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. **The majority of industry supports an applicability which results in the required verification of 80% of the Interconnected MVA. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability.** We feel the applicability section needs further revision, by requiring only generators above 100 MVA with unit capacity factors above 5 % to test, about 30% of the installed generation in New England does not require model validation. We believe this is a large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being stressed the most and reliable operation is being most challenged. We realize that a model for the generators and associated equipment is

Organization	Yes or No	Question 3 Comment
		supplied in accordance with MOD-012 but we feel the accuracy of such models may be limited and a higher percentage of generator validation is required. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard.**

Organization	Yes or No	Question 3 Comment
		Also, the SDT does recognize that regional variances can be considered if a Region desires to include additional unit MVA in this standard. Footnote 4 should be changed to allow verification of generator models not required under the applicability to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical. **Footnote 2 (in the current draft of the standard) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for "technically justified" units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard. Per Footnote 2, a "technically justified" unit is one whose model response does not match the actual equipment response. Industry disagreed with a GV SDT proposal to expand the concept of "technical justification" to include units that were identified through a study to contribute to a stability limit.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration believes that Item 4.2.4 under the "Applicability" section was intended to capture the concept that a Planning Coordinator's request for additional information is limited to NERC-registered units. **Your interpretation is correct** However, the language of requirement R5 will predominate, and it reads as follows:"R5. Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant NOT INCLUDED IN THE APPLICABILITY (our emphasis) that includes one of the following" This provides clear instruction that the entire Applicability section may be

Organization	Yes or No	Question 3 Comment
		ignored - even Item 4.2.4. **Item 4.2.4 has been clarified that only units included in the thresholds listed in the NERC registry criteria would be applicable. The GV SDT feels that this covers the concern of Requirement R5 being misinterpreted** We suggest the following language instead:"R5. Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified1 request from the Planning Coordinator to perform a model review of any NERC-REGISTERED unit/plant not included in the Applicability that includes one of the following"1 Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response Please notice that we also added the footnote under Item 4.2.4 to R5. Although this update is essentially a duplicate, it leaves no doubt to the limits of an exceptional model validation request by the Planning Coordinator. Secondly, MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. We believe that the Planning Coordinator must first engage these entities before issuing such a request to the GO. **It is expected that the vast majority of the time, the Transmission Planner will work with the Generator Operator to resolve model issues for units that are not in the base applicability. The requirement does provide structure to such collaboration to ensure that it can be made to occur in case one of the parties is otherwise unwilling, and to ensure that the required process is bounded with reasonableness.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Duke Energy	No	Footnote 4 - strike the phrase "or plant" in both places, since this only applies to a unit. Also add the phrase "and by demonstrating a reliability need" to the end of

Organization	Yes or No	Question 3 Comment
		Footnote 4. Otherwise, this standard could be made applicable to a small unit that has no impact on reliability.
Response: Thank you for your comment. Though it would admittedly be a rare occurrence, the use of the technical justification concept per Footnote 2 in the current draft of the standard could also apply to a plant. The language in 4.2.4 has been modified to make it clear that only units that meet the NERC Registry Criteria thresholds will be considered.		
Ameren	No	We believe and recommend that this should be the responsibility of the Transmission Planner rather than the Planning Coordinator. At a minimum the language should state "Planning Coordinator and Transmission Planner".
Response: Thank you for your comment. Based on your and other comments, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.		
Cowltiz PUD	No	Technical justification should also include reasonable demonstration that the improved model will improve the Reliability of the Bulk Electric System.
Response: Thank you for your comment. The SDT believes that any correction of any excitation control system model of a unit that is beyond the MVA thresholds set by the Registry Criteria results in more accurate dynamic simulation assessments which does reasonably improve the reliability of the Bulk Electric System.		
Los Angeles Department of Water and Power		LADWP recommends that "technical justification" is defined and/or replaced with more specific language, i.e.:"Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if documentation such as model structure and data values for the

Organization	Yes or No	Question 3 Comment
		excitation control system demonstrates the ....”
Response: Thank you for your comment. The SDT believes that the term “technical justification” is adequately defined per the footnote.		
Texas Reliability Entity	Yes	(a) R5 should be limited to generating units and plants that meet the Registry Criteria. For clarity, we suggest rewording R5 with “...perform a model review of any generation unit or plant meeting the Registry Criteria, but not included as an applicable unit in Section 4.2, that includes one of the following...”. **The SDT agrees that more clarity could be achieved and thus, in response to yours and other comments, revised the verbiage to include the phrase “…that meets NERC registry criteria….”.** (b) Does similar language (i.e. section 4.2.4) need to be added to MOD-027-1? **The GVSDT did not propose a requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and Load control and active power/frequency control system model for a unit not specified in the standard Applicability section. The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next. Please refer back to the GVSDT responses to comments for MOD-027 for additional information.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Arizona Public Service Company	Yes	The SDT has done a great job. The requirement is simple, clearer and supports reliability.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment.		
Southern Company	Yes	Allowing a Planning Coordinator to request additional model information only if technical justification demonstrates a mismatch between the measured unit response and the model's predicted response is appropriate. Even if the unit was a contributor to a stability limit, additional model information is really only needed if the model did not sufficiently emulate actual equipment response.
Response: The SDT thanks you for your comment.		
American Electric Power	Yes	The team might wish to consider if the Transmission Planner should also be included in the applicable facilities 4.2.4 and 5.Point of clarification: one does not "register" units, rather entities are registered for NERC functions.
Response: Thank you for your comment. Based on your and other comments, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.		
Austin Energy	Yes	The standard is not applicable to the Planning Coordinator. Does the SDT mean TP?
Response: Thank you for your comment. Based on your and other comments, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. Thank you for your comment. The Functional Model for the Transmission Planner is more in line with the task described in the standard.		
Georgia Transmission Corporation	Yes	Requirement 5 seems to imply that GO's must provide a written response regarding units below the Registry Criteria unit MVA thresholds (< 20MVA) if a Planning Coordinator provides a technically justified request to perform a model review. Can

Organization	Yes or No	Question 3 Comment
		the SDT confirm this intent? **No - units that could apply to Requirement 5 are units which are below those which would be included per the standard's Applicability section but above units which are included in the NERC Registry Criteria. Also, the SDT decided to replace "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.** Additionally, there could be some confusion with the language as written to imply the PC's "technical justification" includes the bulleted items of R5. **The term "technically justified unit" is defined in the footnote associated with the first occurrence of the term in Section 4.2.4.** GTC is assuming the SDT's intent is for the "GO's written response" to include the bulleted items and therefore requests additional clarity. GTC recommends the following: Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant not included in the Applicability. The written response shall include one of the following [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]: o Details of plans to verify/correct the model documentation and data as needed (in accordance with Requirement R2) o Corrected model documentation and data including the source of revised model data. **The bulleted items in Requirement R3 define the types of written responses that, if received from their Transmission Planner, the Generator Owner would have to respond to per the parameters detailed in the main body of the requirement.**

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. Please see responses above.		
Southwest Power Pool Standards Development Team	Yes	
Puget Sound Energy	Yes	
Dominion	Yes	
Imperial Irrigation District (IID)	Yes	
Western Electricity Coordinating Council	Yes	
Luminant Power	Yes	
Tennessee Valley Authority GO/GOP	Yes	
PacifiCorp	Yes	
Dynegy	Yes	
PSEG	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 3 Comment
American Transmission Company, LLC	Yes	
Luminant Energy	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Southern California Edison Company	Yes	
American Wind Energy Association	Yes	
Pepco Holdings Inc. & Affiliates		No comment
Indiana Municipal Power Agency		no comment

4) To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions. Do you agree with this revisions? If not, please explain in the comment area below.

Summary Consideration: The majority of the industry commenters agreed with specifying the capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, many of the commenters pointed out that neither the net or gross calculation was specified in the standard and suggested the SDT use the "net" calculation. As such, the SDT has revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. This revision was made in Section 4.2 Facilities and in Footnote 4 (now Footnote 2). Finally, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 7) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 4)

Organization	Yes or No	Question 4 Comment
Texas Reliability Entity	No	We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an "applicable unit".
Response: Thank you for your comment. The SDT believes that capacity factor is the best available tool for use to determine a threshold for applicability. Capacity factor has been defined and is already being used in GADS reporting. This standard has been revised to specify the "net capacity factor" is to be used. Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. New units are required to be verified within one year (refer to the table in Attachment 1).		
Luminant Power	No	Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross

Organization	Yes or No	Question 4 Comment
		and Net). The standard should specify Net Capacity Factor.
ank you for your comment. The standard has been revised to specify the "net capacity factor" is to be used. The SDT moved the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 7) in the Periodicity Table. The team would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 4)		
PacifiCorp	No	If the GVSDT intends to incorporate definitions or calculations from Appendix F of the GADS Data Reporting Instructions, the relevant information needs to be expressly incorporated, perhaps in an additional attachment to the standard. Requirements that refer to outside materials are not helpful and should be avoided (notwithstanding the desire to avoid a future need to modify the standard to the extent that Appendix F is amended from time to time in the future).
Response: Thank you for your comment. The SDT believes the reference to the GADS reporting document is appropriate because it is well established and is now a NERC requirement. Including the capacity factor definition into this standard would create the additional problem of having to revise this procedure if the GADS reporting document is revised.		
Luminant Energy	No	Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross and Net). The standard should specify Net Capacity Factor.
Response: Thank you for your comment. The standard has been revised to specify the "net capacity factor" is to be used.		
Duke Energy	No	Need to specify "net" or "gross" capacity factor for the calculation.
Response: Thank you for your comment. The standard has been revised to specify the "net capacity factor" is to be used.		
Austin Energy	No	The NERC Glossary is the correct reference for definitions used in the Standards. Referencing GADS is not appropriate.
Response: Thank you for your comment. The SDT believes the reference to the GADS reporting document is appropriate because it is well established and is now a NERC requirement. The SDT believes that the reference to the GADS reporting document is		

Organization	Yes or No	Question 4 Comment
appropriate, and as such, since it is well established, there is no need to make it a defined term in the NERC Glossary.		
Georgia Transmission Corporation	No	We ought to be able to verify FIDVR mitigating machines below 5% capacity factor.
Response: Thank you for your comment. Units that are below the 5% capacity factor but are equal to or greater than the MVA thresholds in the Registry Criteria could be subjected to the terms in Requirement R5 if there is evidence that the equipment's actual response does not match the model's predicted response.		
Northeast Power Coordinating Council	Yes	While supporting the clarification of capacity factor concerns, there is concern with the exclusion for units with less than a five percent capacity factor. See comments provided to Question 3. Average Capacity Factor should be defined.
Response: Thank you for your comment. The SDT believes that capacity factor is the best available tool for use to determine a threshold for applicability. Capacity factor has been defined and is already being used in GADS reporting. Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely.		
ISO New England Inc	Yes	While we support the clarification of capacity factor, please note our concerns with an exclusion for units with less than a five percent capacity factor that are included with question 3.
Response: Thank you for your comment. The SDT believes that capacity factor is the best available tool for use to determine a threshold for applicability. Capacity factor has been defined and is already being used in GADS reporting. Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration strongly agrees with the SDT's use of the capacity factor calculation used in the GADS system. It is always important to establish links to time-tested parameters - and eliminating any possibility that some other calculation is used.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment.		
Los Angeles Department of Water and Power	Yes	LADWP agrees with this revision.
Southwest Power Pool Standards Development Team	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Puget Sound Energy	Yes	
Dominion	Yes	
MRO NSRF	Yes	
Imperial Irrigation District (IID)	Yes	
PPL Electric Utilities and PPL Supply NERC Registered Organizations	Yes	
Tennessee Valley Authority GO/GOP	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 4 Comment
Massachusetts Attorney General	Yes	
Dynegy	Yes	
AECI	Yes	
PSEG	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
American Transmission Company, LLC	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
Ameren	Yes	
FirstEnergy Corp	Yes	
Southern California Edison	Yes	

Organization	Yes or No	Question 4 Comment
Company		
Cowltiz PUD	Yes	
American Wind Energy Association	Yes	
Indiana Municipal Power Agency	Yes	
Pepco Holdings Inc. & Affiliates		No comment

5. Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-026-1?

Summary Consideration:

The following modifications to the draft standard were incorporated as a result of industry responses to this question:

1) The SDT replaced "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.
2) Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.
3) A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".
4) The SDT has refined section 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability.
5) The SDT refined Part 2.1 to clarify the use of individual and aggregate models for plants.
6) The SDT has re-formatted the Periodicity Table (Attachment 1) to make it clearer that the table is included.
7) Revised the Periodicity Table (Attachment 1) extensively for clarity, including removing specificity regarding when the voltage excursion used for model verification had to be captured. This resulted in a modification of the required times for re-verifying the model for exception (R3 and R4) type activities.
8) The SDT made corrections to VSL verbiage.
9) The SDT made corrections to a reference in Attachment 1 to 356 days (changed to 365 days).
10) In Requirement R5, in describing checking the actual equipment to determine if updated model data could be obtained, the expression "walk down" was replaced by "on-site review" of the equipment.
11) The term "inertia" was modified to "total inertia" in sub part 2.1.3 as some industry commenters expressed concern that reference to "inertia" only would lead to submittal of an inertia constant reflective only of the generator, as opposed to all of the mass attached to the shaft.
12) In Requirement R2, Part 2.1.1, the specific reference to point of interconnection has been removed. The location where the unit's response is measured is left to the model verification entity.
13) The second bullet in Requirement R1 has been modified to be the same style and sentence structure used in the first bullet of R1.

14) The SDT has removed the term "generating plant / Facility" and replaced it with "individual generating plant consisting of multiple generation units that are directly connected at a common BES bus" at the top level of the Facilities section (A4.2).

15) The SDT modified the phrase "generator excitation control system and plant volt/var control functions" to "generator excitation control system or plant volt/var control functions" to recognize that the use of the phrase "or" is technically correct the vast majority of the time.

Organization	Yes or No	Question 5 Comment
Lower Colorado River Authority	Negative	1. Requirement R1- Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) and a requirement placed on the (Planning Authority, Reliability Coordinator, or Resource Planner) to provide data to the Transmission Planner should be added. In ERCOT, the (Planning Authority, Reliability Coordinator, or Resource Planner) and Transmission Planner are separate entities and the (Planning Authority, Reliability Coordinator, or Resource Planner) maintains this information on the ERCOT website, is the first point of contact for new generator interconnection requests, and is the recipient of generation data that is revised after generator compliance testing. The following shows how LCRA TSC's suggested change should be applied to the first paragraph of R1. Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) in the remaining elements of R1. "Each Transmission Planner (Planning Authority, Reliability Coordinator, or Resource Planner) shall provide the following instructions and model data to its requesting Generator Owner or Transmission Planner within 90 calendar days of receiving a request for those instructions or model data:" 2. Requirement R2 - Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) and Transmission Planner. 3. Requirement R3 - Transmission Planner should be replaced with Planning Authority, Reliability Coordinator, or Resource Planner and Transmission Planner in the first paragraph. Transmission Planner should be replaced with (Planning Authority, Reliability Coordinator, or Resource Planner) or Transmission Planner in

Organization	Yes or No	Question 5 Comment
		the sub parts of R3. 4. Requirement R4 - Transmission Planner should be replaces with (Planning Authority, Reliability Coordinator, or Resource Planner) and Transmission Planner. In addition, the requirement to provide the data within 180 days seems excessively permissive since this is after a change has been implemented on the system. LCRA TSC recommends 30 days. The second bullet in Section 4.2.3.2 is confusing. o Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings). 5. Requirement R5 - Allowing generators up to 10 years from the date of regulatory approval to become compliant as stated in Section 5 seems excessively long. In addition, the effective date described in Section 5 appears to be applicable to new generation and modifications to existing generating units, meaning a new or newly modified generating facility would have up to ten years to provide the data. LCRA TSC believes that MOD 26 should be effective immediately to new or newly modified generators who interconnect after the standard is adopted. 6. Requirement R6 - In R6.3, the concern should be when an excitation system and/or volt/var control does not contribute to a well-damped generator response following a fault. LCRA TSC recommends the following changes. " For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model does not contribute to a well-damped generator response."
Response: Thank you for your comment. Regarding the responsibilities that would be assigned to the Transmission Planner in the draft standard, the SDT believes that this arrangement lines up with the vast majority of North American utilities current business practices regarding interactions between generation and transmission entities for collaboration of generator dynamic models. Given that ERCOT is the exception, a regional variance could be considered. Alternatively, the Transmission Planner could		

Organization	Yes or No	Question 5 Comment
delegate the responsibility to others, include their Planning Authority. The transmission planner must maintain a model of their system to meet the TPL standards, but they need input from other embedded entities for generation and other equipment models. For the purposes of the standard, there must be a clear assignment of responsibilities and using “or” in the assignment leaves ambiguity. The SDT has removed the term “generating plant / Facility” and replaced it with “individual generating plant consisting of multiple generation units that are directly connected at a common BES bus” at the top level of the Facilities section (A4.2). As a result of comments received from the prior posting, the standard drafting team extended the time to 180 days to allow more time to work through the technical challenges relating to these models. In order to meet the requirements of the standard, the generator owner needs to have time to schedule someone to test the units, and there needs to be flexibility to allow for units that are not always running, and for such units, often when they are running there are “no touch” rules in place. The 180 days is to provide for enough flexibility to balance the data need with required expenses (especially those associated with running some units) associated with meeting these requirements. New units are required to be verified within one year (refer to the table in Attachment 1). With regard to Requirement R6.3 the SDT believes the language as presently drafted already addresses the commenters stated concerns.		
BC Hydro and Power Authority	Negative	BC Hydro is voting Negative as the motivation and purpose for the 10 year recurring validation period is not clearly defined. BC Hydro recommends supplying better supporting justification, or consideration should be given to modify this criteria, ie remove the blanket 10 year requirement. In place of the blanket interval, alternative criteria recommended are a) for machines equipped with digital excitation and governor control, no recurring testing required because there is nothing that can change (software doesn’t drift), b) for machines with either or both non-digital exciter and governor control, recurring testing should be required every X years (analog control is more susceptible to setting drift and other issues) BC Hydro supports the remaining reasons for requiring validation.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The SDT believes that the ten year periodicity is appropriate and has received industry support for this concept, specifically as a result of the first posting. Digital excitation systems settings can be modified, and there are other components in the closed loop system that can degrade with heat and stress over time (SCRs, discrete electronic components, etc).		
Southwest Transmission Cooperative, Inc.	Negative	Because NERC has made clear that standards are enforced against the BPS and not the BES, the applicability section should be modified to state clearly that it applies to Facilities that are part of the BES. Otherwise small generators that do not affect reliability could be impacted by these standards. NERC enforcement has made this clear in response to comments on CAN-0016 that the CIP-001 standard applied only to the BES. They stated clearly: "According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** The following comments pertain to PRC-024: Use of "new or existing" as a description for the generators in Requirements R1, R2 and R5 is confusing. **This phrase has been removed from Requirements R1 and R2 in PRC-024.** What exactly constitutes new and why is it relevant? The requirements are performance requirements that apply to in-service generators so how does new help explain this further. The footnote in Requirement R5 only further confuses the situation since it is not included in Requirements R1 and R2. Part of the confusion likely centers around Requirement R5 applying to maintaining new generators frequency and voltage excursion performance as well as designing and building it. If "maintain" was removed from Requirement R5, we believe "new" could be removed from Requirement R1 and R2 and they essentially become the maintenance

Organization	Yes or No	Question 5 Comment
		requirements. Furthermore, “new and existing” is not used consistently within other requirements such as Requirement R4. It is not obvious why it would not apply to Requirement R4 it if applies to Requirements R1 and R2. **A new unit is one that is not addressed in Footnote 2 which are units “generating units previously commissioned, or generating units under construction, or generating units with an executed interconnection agreement or power purchase agreement by the effective date of PRC-024-1 Requirement R5.” Requirement R5 applies to future units which must be built to meet the performance requirements of PRC-024. There is no allowance for exceptions or exemptions from any requirement in PRC-024 except as stated in Parts 5.1 – 5.6. Requirement R5 requires the design, construction and maintenance of any future unit once PRC-024 becomes enforceable.** Neither Requirement R1 nor R2 state within the main body of the requirement that the Parts are intended to be exceptions to the requirement. For clarity, there should be a statement (i.e. except when the Parts 1.1 and 1.2 are met) within the requirement the makes this clear. **Requirement R1 now reads, in part, “…with the following exceptions:”Requirement R2 was revised to make the requirement clearer.** For Requirements R1 and R2, it is not clear if the sub-parts are the only reasons that allow for exceptions if other equipment limitations exceptions are allowed. Other equipment limitations should be allowed, and these requirements should be clarified to allow them. **Exceptions for other equipment limitations are addressed under Requirement R3.** As written, Requirement R5 appears to be assumed to apply to a new generator in perpetuity. We draw this conclusion from the inclusion of “maintain” in the requirement. We think it makes more sense to have this requirement apply only to designing and building a new unit and then have the requirements that apply to existing units apply to the maintenance of the new units once they are established.

Organization	Yes or No	Question 5 Comment
		You assumption is correct. That is the intent of Requirement R5. The standard does not appear to allow "new" generating units to have frequency and voltage excursion performance limited by equipment. It should allow "new" equipment as it experiences normal wear and tear as well as damage for any other reasons to document its equipment limited frequency and voltage performance and communicate it similar to Requirements R1 through R3. **Requirement R5 is written with an implementation plan of six years after approval before it is enforceable. This is to allow sufficient time for manufacturers to design and build generation facilities that can meet the performance requirements. Manufacturers have representation on the GVSDT and are aware of this.** Otherwise, a Generator Operator with a "new" generator that has damaged equipment will be forced between operating the unit in a limited manner providing reliability support to the BES and possibly in violation of this standard or taking a forced outage to avoid violating the standard and experiencing escalated penalties for knowingly violating the standard. **Requirement R5, Part 5.5 (was Part 5.6) allows for temporary exemptions to be granted by the Reliability Coordinator in such instances.** We do not believe that Reliability Coordinator is the proper entity to grant a temporary exemption in Part 5.6. Rather, it is the Planning Coordinator that should grant the exemption. Furthermore, this is not consistent with other requirements such as Parts 2.1 and 2.1.1 that specify the Transmission Planner grant the exemption. Of course, Part 5.6 would not be necessary if Requirement R5 did not deal with maintaining the unit and allowed the other requirements that apply to existing units to address maintenance. **Requirement R5 is a performance requirement and is more appropriately addressed in a real-time environment. The GVSDT believes that the Reliability Coordinator is the appropriate entity.** We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The

Organization	Yes or No	Question 5 Comment
		BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary. **The VRF for Requirements R1, R2 and R5 have been revised to "Medium".**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Ohio Edison Company	Negative	FE appreciates the hard work of the drafting team but has some concerns that we ask be addressed so that we can support the standard on the next ballot. Please see our comments and suggestions submitted through the formal comment period.
Response: The SDT thanks you for your comments and has strived to properly consider and respond to all comments and suggestions. Please refer to our responses to your comments.		
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.
Response: Thank you for your comment. After much consideration, and a review of the functional model, the SDT realized that the TP is the appropriate entity to receive the modeling data. In instances where the BA or PA aggregates the model data, the TP		

Organization	Yes or No	Question 5 Comment
is delegating their responsibility under the functional model to other entities.		
Lakeland Electric	Negative	LAK is a member of FMPA, please refer to their comments.
Wisconsin Energy Corp.	Negative	MOD-026-1: Requirement R2.1.1 requires modification to properly include the Transmission Planner in the effort to compare the model response to the recorded response. **The SDT has drafted the standard such that the Generator Owner is the "owner of the model". The vast majority of industry supports this concept, as demonstrated in response to a specific question on the Applicability posed in a prior posting. Peer review type requirements (for example, Requirement R3) have been drafted that can result in the inclusion of the Transmission Planner in a process to review models which result in issues requiring collaboration.** Requirement R2.2 also needs more flexibility for the Generator Owner to provide individual model information in place of an aggregate model for multiple small units. **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** Also, we oppose the addition of Requirement R5 as unnecessary to the reliability of the BES. This Requirement should be removed from the draft Standard. **The SDT believes that Requirement R5 is necessary to the reliability of the BES. This requirement was added by the SDT in response to industry asking if a transmission entity should be allowed to identify additional units beyond those identified in the base Applicability. The base applicability, contains unit and plant MVA thresholds which include a subset of those units which are identified in the NERC Compliance Registry. The ability of the Transmission Planner to request model information is well bounded and defined to ensure that the Generator**

Organization	Yes or No	Question 5 Comment
		Owner is not unduly burdened with frivolous requests for model information.
Response: Thank you for your comment. Please see responses above.		
Omaha Public Power District	Negative	OPPD has signed on to MRO's NSRF comments
Minnkota Power Coop. Inc.	Negative	Please see comments submitted by the MRO NSRF.
MidAmerican Energy Co.	Negative	Please see MidAmerican and MRO NSRF Comments.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Great River Energy	Negative	Please see MRO NSRF comments.
Muscatine Power & Water	Negative	Please see the comments submitted by MRO NSRF
Dairyland Power Coop.	Negative	See MRO NSRF comments.
U.S. Army Corps of Engineers	Negative	See MRO/NSRF comments
Response: Thank you for your comment. Please see responses to MRO comments.		
Fort Pierce Utilities Authority	Negative	Please see separately submitted formal comments by Florida Municipal Power Agency.
Gainesville Regional Utilities	Negative	We support FMPA's position on this matter.
Lakeland Electric	Negative	Please see FMPA comments
Response: Thank you for your comment. Please see responses to FMPA comments.		
Great River Energy	Negative	Please see the formal comments submitted by Aces Power Marketing.

Organization	Yes or No	Question 5 Comment
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.
Response: Thank you for your comment. Please see responses to ACES comments.		
Atlantic City Electric Company	Negative	Refer to comments submitted by Pepco Holdings Inc and Affiliates.
Response: Thank you for your comment. Please see responses to Pepco comments.		
Wisconsin Electric Power Co., Wisconsin Electric Power Marketing	Negative	Requirement R2.1.1 requires modification to properly include the Transmission Planner in the effort to compare the model response to the recorded response. **The SDT has drafted the standard such that the Generator Owner is the "owner of the model". The vast majority of industry supports this concept, as demonstrated in response to a specific question on the Applicability posed in a prior posting. Peer review type requirements (for example, Requirement R3) have been drafted that can result in the inclusion of the Transmission Planner in a process to review models which result in issues requiring collaboration.** Requirement R2.2 also needs more flexibility for the Generator Owner to provide individual model information in place of an aggregate model for multiple small units. **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** Also, we oppose the addition of Requirement R5 as unnecessary to the reliability of the BES. This Requirement should be removed from the draft Standard. **The SDT believes that Requirement R5 is necessary to the reliability of the BES. This requirement was added by the SDT in response to industry asking if a transmission entity should be allowed to identify additional units beyond those identified in the base applicability. The base applicability contains unit and plant**

Organization	Yes or No	Question 5 Comment
		MVA thresholds which include a subset of those units which are identified in the NERC Compliance Registry. The ability of the Transmission Planner to request model information is well bounded and defined to ensure that the Generator Owner is not unduly burdened with frivolous requests for model information.
Response: Thank you for your comment. Please see responses above.		
Consolidated Edison Co. of New York	Negative	See NPCC electric group comments
Response: Thank you for your comment. Please see responses to NPCC comments.		
Occidental Chemical	Negative	See submitted comments on behalf of Ingleside Cogeneration LP
Response: Thank you for your comment. Please see responses to Ingleside comments.		
Northern Indiana Public Service Co.	Negative	There is a concern about inconsistencies between the Standards and Appendices
Response: Thank you for your comment. The SDT has reviewed and simplified Attachment 1 and believe that it is consistent with the draft standard.		
Old Dominion Electric Coop.	Negative	This standard needs a QR as they are many inconsistencies in the language used, I only pointed out a few major errors: R2: You say PC, should be PC or PC must be included in the Applicability Section. **The SDT could not find use of term PC in Requirement R2.** R2: Replace 'Part's with 'Requirements' R2.1: requires GO to comply with a specified TP model, this may not be economic or even feasible to do so. **Regarding ‘Parts’ vs. ‘Requirements’, NERC specifically changed this language to**

Organization	Yes or No	Question 5 Comment
		'Parts' based on the official definition of this term. **Regarding Requirement R2, Part 2.1, the TP models (which are typically standard library models in the PSS/e and PSLF simulation programs) are widely available and representative of excitation systems and volt/var control on all types of generation technologies. While there is no requirement for quality of match between test and simulation, there is a need to assure the TP can use the submitted model in their bulk system analysis (also expanded by language in R6). This is the reason for the language around models acceptable to the TP.** **If your question is related to performance, there is no performance requirement in this standard and therefore there is no need to alter equipment hardware or settings based on these TP models.** R2.2: Parts and Requirements R3: This conflicts with R2 on how the GO must present the data to the TP... **These requirements intend to address separate activities. Requirement R2 is intended to define what is required in the verification. Requirement R3 requires the GO to respond to a TP inquiry.** R5: GO should be allowed to challenge thier units being included by the TP as technically justified! Market issues in RTOs and ISOs. **The intent of Requirement R5 is for TPs to use technical justification for validating models that meet NERC reliability criteria but did not meet applicability criteria. The GO has 90 days to respond. If the GO decides to verify the model, they have a year to do so. The SDT believes that since technical justification requires demonstration the model does not match actual equipment response, this requirement is reasonable.** R6: Perts and Requirements again. Some of my comments are minor, some are deal breakers (R3 and R5). **Regarding 'Parts' vs. 'Requirements', NERC specifically changed this language to**

Organization	Yes or No	Question 5 Comment
		'Parts' based on the official definition of this term.
Response: Thank you for your comment. Please see responses above		
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Response: Thank you for your comment. Please see responses to those comments.		
Pepco Holdings Inc. & Affiliates		Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term "bulk power system." This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term "bulk power system" (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term "Bulk Power System" as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term "Bulk Power System" defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of "Bulk Electric System" (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the

Organization	Yes or No	Question 5 Comment
		BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term "bulk power system" and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition.
Response: We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.		
PacifiCorp	Yes.	See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and

Organization	Yes or No	Question 5 Comment
		o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **The SDT has refined section 4.2.2 of the Facilities section under Applicability and Part 2.1 to clarify the use of individual and aggregate models for plants.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows:"For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6." **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.**
Response: Thank you for your comment. Please see responses above.		
Ameren		(1) The requirements 4.2.1.1 and 4.2.1.2 refer to bulk power system (BPS). We suggest that GVSDT includes definition of BPS in the standard. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** (2) We suggest that GVSDT clearly specify that "point of interconnection" referred to in R2.1.1 to be the same as defined in PRC-024-1.

Organization	Yes or No	Question 5 Comment
		Specific reference to point of connection is removed from R2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance." (3) In Attachment 1, Row 4 it seems to imply to us that some use of "Sister Units" is allowed to meet the requirement. . We suggest that the GVSDT clarify and include this option in the body of the Standard (preferably) or in Attachment 1 as an option? **The proxy or sister unit concept is intended to be a part of Attachment 1. The SDT has re-formatted the Periodicity Table (Attachment 1) to make it clearer that the table is included.** (4) Requirement R2.2 states that an Applicable plant with gross nameplate ratings of the units < 20 MVA should use a plant aggregate model. Can the GVSDT clarify the type of model and provide example for each? **The SDT wants to avoid including specific examples in the standard at risk of creating bias or confusion to its captive audience. That said, a primary reason for this language is to capture variable energy resources (wind and large solar plants) that are widely modeled using an aggregated equivalent generator rather than separately modeling each machine. One example would be using the WECC generic wind models (which are aggregate models) to represent wind plants. Also, Part 2.1 contains refined verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** (5) There are 17 technical papers referenced in Section G of the Standard. Would the GVSDT make them available on the NERC website? **Information necessary to obtain copies of these papers is listed in each of the**

Organization	Yes or No	Question 5 Comment
		paper references. (6) For Requirement R3, we did not find anything in the standard that specifies how closely a model response must match the tested response of a generator. We believe that unless this is clearly specified, it could lead to disagreements between the Generator Owner and Transmission Planner over what constitutes a verified model. **The SDT has drafted the standard such that the Generator Owner is the "owner of the model". The vast majority of industry supports this concept, as demonstrated in response to a specific question on the Applicability posed in a prior posting. Requirement R3 is a "peer review" type requirement that can result in the inclusion of the Transmission Planner in a process to review models which result in issues requiring collaboration. However, as owner of the model, the requirement is structured such that the Generator Owner is both responsible and has the final say in collaboration regarding model issues.**
Response: Thank you for your comment. Please see responses above.		
Texas Reliability Entity		1) Applicability: The applicable Facility requirements should be the same for every Standard in this Project! **The applicability of MOD-026 is carefully selected in an attempt to balance the need for verified models with the cost and effort required. The size requirements are selected to assure that 80% of the generation MVA represented has verified models. Also, the effective and implementation dates for the current drafts of MOD-026 and MOD-027 (dynamic model verification standards) are effectively the same.** 2) Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection.

Organization	Yes or No	Question 5 Comment
		Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term. 3) Effective Dates: Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correcting model errors that may lead to (or have led to) improper planning of the system based on the current model results. **The purpose of the initial 10-year implementation period is to give industry sufficient time to perform verification on required units with limited resources to perform the verification activities. The SDT believes that 10 years is a reasonable re-verification period. The standard does include requirements that obligate the Generator Owner to possibly re-verify the model before 10 years upon the occurrence of certain activities, including a change in equipment expected to modify the output of the equipment. The proposed 10-year re-verification period is also supported by an overwhelming majority of comments received from the industry.** 4) The SDT should consider moving the "Consideration for Early Compliance" criteria from Attachment 1 into the Effective Dates section. **The SDT has reformatted Attachment 1 for improved clarity. The consideration for early compliance could be included in section 5, "Effective Date", but we believe the flow of the standard is best if the early compliance information appears in Attachment 1 with the other clarifying criteria.** 5) Regarding Requirements R3 and R4: The inclusion of "or a plan" extends the timeframe associated with getting good modeling data to the TP. What does the Transmission Planner do in the interim? Who is responsible for the use of the unusable or invalid data? Does the unusable or invalid data get used at all (do the plants need to disconnect until "usable" data is provided)? **The draft standard realizes that upon recognition of an issue with the model, the**

Organization	Yes or No	Question 5 Comment
		investigation of the issue and ultimately the implementation of the solution does take time. Both parties will be motivated to resolve the model issue as quickly as possible. Thus, in practicality, the process does require time as it does currently today. The decision on what model to use for dynamic studies in the interim would be made by the Transmission Planner, ideally after consultation with the Generator Owner. 6) Regarding VSLs for R1, R3, R4, R5 and R6: The numbers of days stated in the Severe VSLs need to be reconsidered. For example, in the Severe VSL for R1, no VSL applies if the performance occurs on day 181. **Based on your comment, the SDT has revised the verbiage for the Severe VSL for Requirement R1 to "The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a request."** 7) Regarding VSL R5: There is reference to Subpart(s) 5.2 and 5.3 in the High and Severe VSL text, but there are no corresponding subparts in the Standard. **Based on your comment, the SDT has revised the verbiage for the High VSL to not include any references to the sub bullets in Requirement R5, and revised the verbiage for the Severe VSL to include " OR The Generator Owner written response failed to indicate one of the sub bullets of Requirement R5."** 8) Regarding Attachment 1: The allowed time to provide usable verified models is far too long. For example, as written there could be a gap of almost two years between the time a TP learns that a model is "unusable" and the time the GO has to provide a verified model. **The SDT drafted the standard recognizing the model verification requires expertise and calendar time. Regarding the specific example offered, the SDT believes that the vast majority of the time, issues regarding model usability will be resolved very quickly. Typical issues include scaling issues, model data typos, incorrect per unit calculations, etc. Typically, a model that is found to be not**

Organization	Yes or No	Question 5 Comment
		useable does not result in the model having to be re-verified. In the interim, after an initial consultation with the Generator Owner, the Transmission Planner may choose to use the prior model. **Also, in part as a goal to further simplify and streamline the Periodicity Table (Attachment 1), the maximum amount of time between the Transmission Planner learns and notifies the Generator Owner that a model is "unusable" and (assuming the Generator Owner decides to verify the model) when the Generator Owner transmits a re-verified model is decreased to 1 year 90 days. (instead of 1 year 270 days as proposed in the previous posting).** 9) In Attachment 1, change "356 days" to "365 calendar days" in the third line of the table for consistency. **The typo error correction has been made.**
Response: Thank you for your comment. Please see responses above.		
Ingleside Cogeneration LP		1. Ingleside Cogeneration LP cannot agree with the change in the applicability section of MOD-026-1, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** 2. What could possibly be a technical justification for including generators below that included in the Applicability Section. Without this in the Standard, it leaves

Organization	Yes or No	Question 5 Comment
		it open to whatever the PC is inlinded to do. If you have a "catch all" requirement, you need to have a specific set of technical requirements to limit the PC's discretion. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard. The technical justification for a request is described in a footnote reference in the standard (see section 4.2.4) – in summary, the TP must demonstrate that the simulated unit or plant response does not match the measured unit or plant response.** 3. Registered Entities below the individual unit thresholds of 100MVA, 75MVA, and 50MVA do not need to be modeled unless there is technical justification. This is a significant burden on small generators. Small generators should only be required to provide model verification where the PC can show justification through a set of criteria. **The SDT believes that smaller units that meet NERC registry criteria connected to BES system can have a significant role in the stable operation of the grid – especially when in aggregate they meet or exceed the plant thresholds in the standard.**
Response: Thank you for your comment. Please see responses above.		
We Energies		a. In Section A3. reference is made to Bulk Electric System (BES) reliability. Then, in Section A4, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**

Organization	Yes or No	Question 5 Comment
		b. In Requirement R1, instead of the TP providing "instructions", the standard should require the TP to simply "provide" the model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. **The software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission Planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** c. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple generating units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the need to develop these equivalent models. The requirement should be more flexible to allow the GO the option to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate model. **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** **The genesis of this language around aggregated models was to address Variable Energy Resources (wind and large PV solar plants) where the standard practice is to use a single aggregated generator and collector model to represent all wind turbines or solar inverters in a plant with like technology. Aggregated models for**

Organization	Yes or No	Question 5 Comment
		renewable energy plants are available either from the OEM or via WECC's generic models and there shouldn't be an issue obtaining at least one of them. d. In R2.1.1, the GO is required to provide documentation that the generator model response matches the recorded response for a voltage excursion. Since the GO often does not have the capability to run dynamic studies, how will it obtain the "model response" for comparing to the recorded response? We suggest that this requirement be modified to require that the GO "provide the recorded response for a voltage excursion". As presently written, R2.1.1. can only be required of the TP. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. The draft standard does not require the generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. Finally, agreements between the Transmission Planner and the Generator Owner can be arranged for the Transmission Planning entity to perform portions or all of the model verification process however responsibility for model verification remains with the Generator Owner.** Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the voltage data as required in R2.1.1. There needs to be a recognition that the Transmission Planner

Organization	Yes or No	Question 5 Comment
		and Generator Owner will need to work cooperatively on this. The goal is good, but this standard is not nearly developed enough to be a useful standard. **Recording equipment needed to capture voltage data is widely available. The SDT does recognize that expertise in performing model verification is limited, and that entities will need time to either hire consultants to perform the verification or develop the expertise in house – thus the staged ten year Implementation Plan.**
Response: Thank you for your comment. Please see responses above.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations		a. Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of running dynamic models or representing within the model the system we connect-to. **The draft standard does not require the generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits.** R2.1 1 should require the TP, not GOs, to run models and develop the referenced documentation (or, if the result is not suitable, open a dialogue per R3). The same comment applies for R2.2. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the**

Organization	Yes or No	Question 5 Comment
		Transmission Planner. Finally, agreements between the Transmission Planner and the Generator Owner can be arranged for the Transmission Planning entity to perform portions or all of the model verification process however responsibility for model verification remains with the Generator Owner. b. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. **The SDT consciously avoided definitions of how tests are performed as well as quality of match between model and test to avoid risk of being over-prescriptive and too restrictive. The focus is solely on "what" is required, not "how" it's done. Ultimately, the Generator Owner and their testing and model validation entities are left to determine the appropriate tests and responses to validate models against, as well as determining how well the model represents the as-installed equipment.** The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026. It was stated in the 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion is not included in the draft standard. **Again, the focus is solely on "what" is required, not "how" it's done. Ultimately, the Generator Owner and their testing and model validation entities are left to determine the appropriate tests and responses to validate models against, as well as determining how well the model represents the as-installed equipment.** c. We suggest replacing "rotational inertia" in R2.1.3 with "inertia constant (H)," the

Organization	Yes or No	Question 5 Comment
		rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. **In mentioning the rotational inertia, the SDT is providing examples of the types of data included to help understanding, and did not intend to specify the base that should be used in providing the data. The standards attempt to specify what is required, and hence do not provide the details regarding the data to be provided. However, for clarity, the term "inertia" in sub part 2.1.3. was modified to "total rotational inertia" as some industry commenters expressed concern that reference to "inertia" only would lead to submittal of an inertia constant reflective only of the generator, as opposed to all of the mass attached to the shaft.** d. The 4/6/10-year periods specified in paras. 5.1.1-5.1.4 and 5.2.1-5.2.4 on pp. 3-4 of MOD-026-1 should provide for existing plants enough time to catch a disturbance of sufficient magnitude for verification purposes; but the one-year allowance in row 3 on p.15 for plants that are new or have replaced controls equipment may prove inadequate, especially since (per comment 5b above) we don't currently know what sort of transient is needed. At least a four-year window should be granted for the initial verification. It is also unclear how one decides up-front the applicability of this standard to a new facility. The past-years test of para. 4.2 cannot be used; and a unit anticipated to have less than a 5% capacity factor may prove otherwise depending on market conditions or other factors. In any event the one-year verification limit for new and modified units is inadequate if it takes longer than this amount of time just to determine whether or not MOD-026-1 is applicable. **The SDT believes that a new excitation control system will be tested during commissioning and the test data will be adequate to comply with this standard. Whether or not a new unit may have a capacity factor of greater than 5%, it should still be commissioned with initial testing of the excitation control system. If additional time is needed to create a model from the test data, the SDT believes that 1 year is adequate. The standard requires each new unit to be modeled within one year.**

Organization	Yes or No	Question 5 Comment
		e. The use of the undefined term “technically justified request” in R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? Further, the 90 day time period should not begin until both parties fully understand the “technically justified request.” **The technical justification for a request is described in Footnote 2 of the current draft of the standard. The technical justification request in Requirement R5 is intended to perform a model review for any unit/plant not included in the applicability section of the standard. The 90 day grace period in Requirement R5 is intended for the Generator Owner to perform a review and submit a written response to Transmission Planner’s request. The 90 days grace period is not intended for Generator Owner to perform model verification.** f. The means by which a walk-down would lead to identification of model parameters in the second bull-dot of R.5.2 is not understood. **The text has been modified and the expression “walk down” was replaced by “on-site review” of the equipment.**
Response: Thank you for your comment. Please see responses above.		
Independent Electricity System Operator		a. Requirement R2.1: We continue to disagree with the phrase “models acceptable to the Transmission Planners” as it is a potential source of dispute between the TP and the GO. Requirement R1 already asks the TP to provide instructions and model data to its requesting GO but makes no reference to “acceptability”. To avoid potential disputes, we suggest that R2.1 be reworded to:R2.1. Perform verifications using one or more models provided by the Transmission Planner in R1, that include(s) the following information: **In the current draft, bullet one in Requirement R1 makes provisions for the Transmission Planner to provide instructions for the Generator Owner to acquire models that are acceptable to the Transmission Planner. The SDT believes that the subsequent phrase in Requirement 2 which reads “perform verification using one**

Organization	Yes or No	Question 5 Comment
		or more models acceptable to the Transmission Planner" sufficiently specifies the link to Requirement R1 bullet one. b. We continue to disagree with Parts R6.1 to R6.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model, especially if such devices are new for which there are no previous simulations to benchmark with. **The SDT believes that excitation systems and other closed-loop control systems in a power plant (barred some mal-function or failure) are commissioned to provide stable and properly damped response. Thus, validated simulation models should exhibit a similar response and that can be easily assessed using simulations as those described in Part 6.1 to Part 6.3. On the other hand, a model that does not exhibit a stable and properly damped response to these simulations described in Part 6.1 to Part 6.3 is probably not representing the actual behavior of the equipment and this discrepancy should be addressed before the model is accepted and deemed usable.** A computer model may fail to initialize due to reasons other than inaccuracy in the submitted excitation control system and plant volt/var control function model itself, and a no-disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. System damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. **The models can be tested, as described in Part 6.1 to Part 6.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.**

Organization	Yes or No	Question 5 Comment
		In short, having an accurate excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three parts. We suggest this requirement be removed. **The Part 6.1 to Part 6.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.**
Response: Thank you for your comment. Please see responses above.		
Duke Energy		o R2, 2.1.3 - Please revise to specify total inertia. Total unit inertia should be given to include all coupled rotating elements. The way this is currently worded, it could lead generators to only provide the generator H values. **The SDT has modified the term to include "total" rotational inertia as suggested.** o R2, 2.2 - Insert the phrase "or individual unit" after the word "aggregate". **Requirement R2 Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation.** o Page 15, Equivalent applicable unit - Identically designed generation units are identical in control response, independent of site location. New techniques for validation eliminate the impact of the grid on the validation efforts. Thus, credit for sister unit validations should be available independent of the location of a unit or connected voltage. **The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during**

Organization	Yes or No	Question 5 Comment
		a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.
Response: Thank you for your comment. Please see responses above.		
American Transmission Company, LLC		ATC recommends that the SDT give consideration to the following:1. In Requirements, R1, bullet 2 - change the wording to be more similar to bullet 1, "obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations". Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets, allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. **The standard drafting team has revised the wording of Requirement R1 bullet two. Also, it should be noted that the software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** 2. In Event Triggering Verification Table, Item 6, Cell 1 - fix typographical error of ". . . system event did not "did not" match . . ." **The typographical error has been corrected.**

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Please see responses above.		
ERCOT		1: Requirement R2 and voltage ride through curve in the PRC-024 Attachment 2 are applicable to the voltage at point of interconnection to the Bulk Electric System (BES). However, in requirement R2.1 "When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:" The clarification is needed for R2.1 that describes how the generator terminal voltage will affect the applicability to this requirement. **The clarification phrase has been removed and Requirement R2 has been restructured to provide more clarity around when it is acceptable for the unit to trip.** 2: In the attachment 1 and attachment 2, it is not clear if a unit can be allowed to trip instantaneously under extreme high voltage or high/low frequency occurred during and post disturbance period. For example, the physical limitation requires a wind farm to trip the turbine instantaneously when voltage is above 1.25 pu. If there is a short duration of overvoltage, 1.3pu for 0.15 second, during and post disturbance period that cause the wind farm trip the turbines, does this wind farm violate the requirement as stated in attachment 2 that requires the wind farm to remain in service for 0.2 second when voltage is above 1.2 pu? **Tripping of a unit or plant is allowed anywhere outside of the curves. The table in attachment 2 has been revised and now has an entry that allows for instantaneous tripping when the voltage is greater than or equal to 1.20 pu.**
Response: Thank you for your comment. Please see responses above.		
Cowltiz PUD		Cowlitz PUD respectfully disagrees with the use of the statutory term bulk[-]power system in the applicability section of any reliability standard. This term is not

Organization	Yes or No	Question 5 Comment
		adequately defined to be used anywhere excepting arguments as to whether a proposed standard falls within the jurisdiction of the Federal Power Act of 2005. Use of the statutory term will hamper any future efforts to revise the Statement of Compliance Registry Criteria. The Bulk Electric System is a subset of the bulk-power system. If the intent of the SDT is to include any generation of stated MVA name plate capacity connected to a "transmission system" operated at an undefined voltage, the result will be to defeat work being done to technically justify exclusion of certain bulk-power system facilities which have no substantial impact on Reliability. If however, the intent of the SDT is to follow the Statement of Compliance Registry Criteria and imply that the "BPS" is equal to the BES, it is preferable to specify generation connection voltage than use BPS. Cowlitz agrees that non-BES generation may need to be included in this standard's applicability section (as users of the BES), however specific generation that a particular GO may own which by itself would not have required registration of the entity should not be inadvertently included in the applicability of this standard.
Response: We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.		
FirstEnergy Corp		FirstEnergy would like to make the following comments on this standard: 1) Under the Applicability section 4.2.1.2, the use if the term "common bus" should be clarified as either the low-side or high-side of the GSU. **The SDT team believes that the consistent use of the term "directly connected to the Bulk Electric System" in the current draft of the standard makes it clear that it is referring to the high side of GSUs of 115 kV or greater.** 2) Footnote 1a on Page 2, says that "... the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer."

Organization	Yes or No	Question 5 Comment
		While we understand that the excitation system supplies the generator field, there is a separate Model for the Generator (typically GENROU). We suggest omitting the word generator from the footnote to avoid confusion. **The SDT believes that the generator is an integral part of the voltage/reactive power control loop and thus an essential part to the validation of the excitation control system response. As such, there is no separate Standard regarding the validation of the generator model, so the SDT believes there is no conflict or confusion regarding the validation of the generator model.** 3) Suggest rewording 2.1 to begin with, "Provide models acceptable to the Transmission Planner, including verified parameters ...", rather than "Perform verifications ...". The GO provides information on applicable models as well as the parameters. The TP actually runs the models to determine system impact. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner.** 4) Requirement 2.1.1 requires "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion at the applicable unit's point of interconnections from either a staged test or a measured system disturbance. O Please define or qualify the term "matches". This is a subjective term, subject to interpretation of results; i.e., what % error is considered "matching". **The SDT consciously avoided definitions of how tests are performed as well as**

Organization	Yes or No	Question 5 Comment
		quality of match between model and test to avoid risk of being over-prescriptive and too restrictive. The focus is solely on "what" is required, not "how" it's done. Ultimately, the Generator Owner and their testing and model validation entities are left to determine the appropriate tests and responses to validate models against, as well as determining how well the model represents the as-installed equipment. oRefers to recorded response "... at the applicable unit's point of interconnection ...". This should be reworded to "at generator terminals". An excitation system controls to the generator terminals since this is where Voltage and Current inputs to the AVR originate. Further, this is where measurements are taken during dynamic testing. **Specific reference to point of connection is removed from Requirement R 2, Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."** o"a measured system disturbance" is not practical for a GO, and should be eliminated. DME is owned by the TO, and do not have access to results of disturbances. **The intent of this language is to allow GO's to use recorded data (if they have it) from a known system event as a means to validate an exciter or volt/var control model against. Ultimately, the usability of this or any data to validate a model against is at the discretion of the GO and their testing and model validation entities.**
Response: Thank you for your comment. Please see responses above.		
American Electric Power		For section 4.2 we suggest the term "bulk power system" be replaced with "Bulk Electric System". BES is currently being defined, while bulk power system currently does not have a definition and thus is ambiguous.

Organization	Yes or No	Question 5 Comment
		Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term. In the second bullet of 4.2.1.2, one of the words “comprised” or “consisting” needs to be removed as they are redundant. Also, we are confused by the bullets in 4.2.1.2 which should be re-worded to clarify the intent. For example, would diesel generators at a larger facility be in scope of this requirement? Furthermore, the qualifier between the two bullets should be “or” rather than “and”. **The section was re-written to provide clarity and in the process, the word “comprised” was deleted. With the new language, the qualifier between the bullets is correct.** For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year. **The effective date is specified using standard language that is well known and understood.** Throughout the standard, “generator excitation control system and plant volt/var control function model” should have an “or” rather than an “and”. **The SDT implemented your suggestion.** The second footnote in requirement 4 could be interpreted to be all-inclusive. Please check the numbering of all footnotes and the pages that those footnotes reference. References should only be made to footnotes on the same page as the referring number. **The SDT has made the aforementioned corrections.**
Response: Thank you for your comment. Please see responses above.		
Indiana Municipal Power		IMPA believes that the reference of “bulk power system” should be replaced with

Organization	Yes or No	Question 5 Comment
Agency		Bulk Electric System throughout the standard. Bulk power system is used in the Compliance Registry, but it is not a NERC defined term. FERC even agrees that bulk power system goes beyond the Bulk Electric System (FERC Order 693). **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** IMPA is troubled by the requirement in R2.1.1 that requires a voltage excursion from a staged test or a measured system disturbance. Are there an ample supply of contractors or consultants that can perform such a test? What is the risk to a unit to perform the staged test? **A staged test to obtain data to verify excitation control system models does not typically involve an actual BES voltage excursion. A stage test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.**
Response: Thank you for your comment. Please see responses above.		
Los Angeles Department of Water and Power		LADWP supports the language under Attachment 1, "Consideration for Early Compliance".
Response: Response: Thank you for your comment.		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons: 1 - Implementation time frames - the implementation plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.

Organization	Yes or No	Question 5 Comment
		MOD-024 and MOD-025 have now been combined. The verification of steady state MW and MVAR capabilities would be accomplished by test which is distinctly different than the activities required for verification of excitation control systems. Also, the verification of steady state MW and MVAR capabilities would be accomplished without taking the unit out of service. Personnel involved in steady state MW and MVAR capabilities will almost certainly be different than personnel involved in the verification of excitation control systems. Also, the verification of excitation control systems per the current draft of MOD-026 will almost always be ten years, whereas the periodicity of steady state MW and MVAR capabilities per the current draft of MOD-025 is only five years. MOD-012 and MOD-013 are simply data submittal standards as opposed to data verification standards. Also, the effective and implementation dates for the current drafts of MOD-026 and MOD-027 (dynamic model verification standards) are effectively the same. 2 - R5 'walk down' - the requirement of a 'walk down' of equipment in R5 is unclear. Manitoba Hydro suggests that the wording be revised to 'based on an onsite review of the equipment. **The text has been modified and the expression "walk down" was replaced by "on-site review" of the equipment.** '3 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. **Entities need to be able to demonstrate that they are compliant with the standard, regardless of the date of the last audit. The drafting team used the boilerplate language endorsed by the Standards Committee.**

Organization	Yes or No	Question 5 Comment
		Manitoba Hydro also suggests that synchronous condensers be included in MOD-026. **The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers.**
Response: Thank you for your comment. Please see responses above.		
Entergy Services		MOD-026-1 R2.1.1 is:2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion at the applicable unit's POINT OF INTERCONNECTION from either a staged test or a measured system disturbance. We recommend the POINT OF INTERCONNECTION be changed to GENERATOR TERMINALS.
Response: Thank you for your comment. Specific reference to point of connection is removed from Requirement R2 Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."		

Organization	Yes or No	Question 5 Comment
Progress Energy		Our AFFIRMATIVE vote is conditional upon the "Clean" version being voted on. There are major differences between the Red-line and clean version in Section 5 "Effective Date". The Clean version 5.1.3 requires 50 % where as Red-line version has 100 %
Response: Thank you for your comment. The clean version is the appropriate version to reference if there are any differences between the clean and red line versions.		
MRO NSRF		Please give consideration to the following suggestions from the MRO NSRF: 1. In Requirements, R1, bullet 2 - change the wording to be more similar to bullet 1, “obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations”. Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. **The standard drafting team has revised the wording of Requirement R1 bullet two. Also, it should be noted that the software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission Planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** 2. In Event Triggering Verification Table, Item 6, Cell 1 - fix typographical error of “. . . system event did not did not match . . .” **The typographical error has been corrected.** 3. Please restructure requirements and evidence to allow for posted instructions and model data to meet compliance for appropriate requirements such as R1,R2, etc...

Organization	Yes or No	Question 5 Comment
		Response: The SDT apologizes but we could not determine your question. 4. In the second bullet item under Applicability Section 4.2.1.2, recommend the drafting team remove the word "consisting" and add the word "solely" to avoid confusion. Section 4.2.1.2 would instead read "Each generating plant / Facility comprised consisting solely of ...". **Section 4.2.2 of the standard applicability has been revised and the word "consisting" has been deleted.** 5. Recommend the capacity factor test in Applicability Section 4.2 be revised to state: "Applicable units or plants with an average capacity factor greater than 5 percent ..." As currently drafted, it is unclear as to whether all units, applicable or not, are included in the calculation of the Capacity Factor (CF). In cases where an entity has a plant with one 60 MVA unit and three 15 MVA units, the units less than 20 MVA would not be applicable per the criteria in MOD-026-1. However, would all units still be factored into the CF calculation? **The capacity factor statement in section 4.2 is the first qualifying statement for applicability of all units. Any unit that does not meet the capacity factor qualifier is not included in the standard. Any unit that does meet the capacity factor qualifier is then subjected to the next qualifiers of MVA rating and connection to the BES. The SDT does not believe that the use of the word "applicable" in the capacity factor qualifier would clarify the standard.** 6. Requirement R6.3 specifies "a disturbance simulation results in .... exhibiting positive damping". Guidance is needed as to what is considered acceptable positive damping. **The SDT believes that excitation systems and other closed-loop control systems in a power plant (barred some mal-function or failure) are commissioned to provide stable and properly damped response. Thus, validated simulation models should exhibit a similar response and that can be easily assessed using simulations as those described in Part 6.1 to Part 6.3. On the other hand, a model that does not**

Organization	Yes or No	Question 5 Comment
		exhibit a stable and properly damped response to these simulations described in Part 6.1 to Part 6.3 is probably not representing the actual behavior of the equipment and this discrepancy should be addressed before the model is accepted and deemed usable. It should be noted that Part 6.1 to Part 6.3 are related to the usability of these validated models in system studies, not exactly with the validation. 7. R6 has two periods at the end of the paragraph just before [Violation Risk Factor ...] **This has been corrected in this revision.** 8. In the applicability section 4.2, the undefined term bulk power system is used. To avoid confusion regarding the applicability, it is recommended the defined term Bulk Electric System be used. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**
Response: Thank you for your comment. Please see responses above.		
ReliabilityFirst		ReliabilityFirst abstains on the MOD-026-1 ballot and offers the following comments for consideration: 1. Facilities a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality**

Organization	Yes or No	Question 5 Comment
		dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 1000 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. The SDT asked a specific question on the Comment Form regarding the proposed applicability, and the response to the question reflected Industry concurrence with this approach. 2. Requirement R1 a. For the purposes of NERC standards, "bullets points" are to be considered "OR" statement. ReliabilityFirst believes all the "bullets points" in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) **The SDT believes that these bullet points are "OR" statements, at least to the sense that a Generation Owner might not have requested all three items listed in the bullets. The requirement is meant to be that the TP should provide the information requested by the GO.** 3. Requirement R5a. ReliabilityFirst is unclear on the meaning of the term "walk down of the equipment" in the second bullet? ReliabilityFirst request further clarification of the term "walk down of the equipment?"

Organization	Yes or No	Question 5 Comment
		The text has been modified and the expression "walk down" was replaced by "on-site review" of the equipment. 4. Requirement R6a. ReliabilityFirst requests further clarification on the term "initializes" as referenced in Subpart 6.1. Is this in the context of excitation control system and plant volt/var control function model initialization within a PSSE application? **The SDT wants to reiterate that model usability is a different issue than model validation. The objective of Part 6.1 to Part 6.3 is to assess the usability of the models in system simulations (e.g. PSS/E, PSLF or whatever simulation tool being used). The tests listed in these requirements are expected to be typically performed when a new model is incorporated to the simulation database.** 5. Section G. References. ReliabilityFirst recommends removing the references in Reference Section G and place it into a reference type document. Even though this good information, it is not needed in a Reliability Standard. **The SDT believes the references are useful to some users and should be provided in the most helpful location. In some cases, references are included in a NERC standard instead of moving them to a separate document.** 6. VSL Requirement R2a. Requirement R2 contains a sub-part 2.2 which is not mentioned in the corresponding Violation Severity Level (VSL). ReliabilityFirst recommends including a VSL covering Subpart 2.2. Here is an example of a "lower" VSL: "For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA in Requirement R2, Subpart 2.2, the Generator provided the Transmission Planner verified models, using plant aggregate model(s), that omitted one of the six Parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6." **Requirement R2, Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or**

Organization	Yes or No	Question 5 Comment
		plant aggregate models or any combination therein as dictated by the specific situation. A VSL does exist in the current draft for Part 2.1. 7. VSL Requirement R5 a. The VSL for “High” and “Severe” mention Subparts 5.2 and 5.3 though there are no associated subparts referenced in Requirement R5 (there are only 2 bullet points). ReliabilityFirst recommends removing the references to Subparts 5.2 and 5.3. **Based on your comment, the SDT has revised the verbiage for the High VSL to not include any references to the sub bullets in Requirement R5, and revised the verbiage for the Severe VSL to include “ OR The Generator Owner’s written response failed to include one of the sub bullets of Requirement R5”** 8. VSL Requirement R6a. R6 requires the Transmission Planners to “...notify the Generator Owner within 90 calendar days... “, while the corresponding VSL states “The Transmission Planner provided a written response to the Generator Owner indicating...” **The reference to the required time frame in the VSL is included.** Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," ReliabilityFirst recommends the following as an example of the “Lower” VSL: “The Transmission Planner notified the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R6)” **The SDT believes that all of the relevant information is addressed in an acceptable format in the current version of the VSL.**
Response: Thank you for your comment. Please see responses above.		
Florida Municipal Power Agency		The applicability refers to the “bulk power system”, e.g., “4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to

Organization	Yes or No	Question 5 Comment
		the bulk power system". The term "bulk-power system" should not be used in the standards as it is ambiguous and should be replaced with "Bulk Electric System". We do not understand how the Applicability of 4.2.1.2 means. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** We suggest making the language clearer.R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. **A staged test to obtain data to verify excitation control system models does not typically involve an actual BES voltage excursion. A staged test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.** R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. **Changes in operating mode (auto/manual, PSS on/off, etc.) do not trigger the need to provide a revised model or re-verification as described in Requirement 5. The following sentence has been added to Footnote 4 in the current draft of the standard to clarify the intent: "Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement 5".** R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualified? **The technical justification for a request is described in Footnote 2 of the current**

Organization	Yes or No	Question 5 Comment
		draft of the standard.
Response: Thank you for your comment. Please see responses above.		
City of Vero Beach		The applicability refers to the "bulk power system", e.g., "4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system". The term "bulk-power system" should not be used in the standards as it is ambiguous and should be replaced with "Bulk Electric System". We do not understand how the Applicability of 4.2.1.2 means. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** We suggest making the language clearer.R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. **A staged test to obtain data to verify excitation control system models does not typically involve an actual BES voltage excursion. A staged test typically involves injecting a step change signal into the unit's voltage regulator – which makes the voltage regulator "think" that a voltage excursion has occurred. Usually a laptop PC can be used to record the resulting staged testing data. There has been ample experience in industry with safely and effectively using a staged test.** R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. **Changes in operating mode (auto/manual, PSS on/off, etc.) do not trigger the need to provide a revised model or re-verification as described in Requirement 5. The following sentence has been added to Footnote 6 to clarify the intent: "Automatic changes in settings that occur due to changes in operating mode do not apply to**

Organization	Yes or No	Question 5 Comment
		Requirement R5". R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualified? **The technical justification for a request is described in Footnote 2 of the current draft of the standard.**
Response: Thank you for your comment. Please see responses above.		
Dynegy		The division of responsibility (between GO and TP) in the task of 'verifying' the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and 'verify' the models. This would also eliminate the question of what constitutes a 'verified' model, i.e., how good is good enough.
Response: Thank you for your comment. The SDT considered who should be the owner of the model and asked Industry during the first posting. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. For all of these reasons, the SDT believes that the Generator Owner is the appropriate entity to perform model verification activities. Finally, as the owner of the model, the peer review Requirement R3 clearly states that the Generator Owner has the final say for any technical discussions regarding the model. Finally, the Generator Owner could pursue entering an agreement with the Transmission Planner to perform portions or all of model verification. However, the Generator Owner would still be responsible from a compliance perspective.		
Western Electricity		The introduction to this comment form indicates that "The typographical errors in R2.1.1 language has been corrected to clearly state expectation that, "The unit or

Organization	Yes or No	Question 5 Comment
Coordinating Council		plant's model response matches the recorded response for a voltage excursion at the generator or plant point of Interconnection..." However, the versions posted for review (clean and redline) do not indicate that the "unit or plan's model..." They say the "applicable unit's model response matches..." There is no reference to plants in part 2.1.1
Response: Thank you for your comment. In the Applicability section 4.2 (Facilities), the first sentence reads "For the purpose of this standard, the following Facilities are considered…."applicable units" Units or plants that meet the following ….." . As such, references in the standard to "applicable units" includes units and plants. A reference to an "applicable unit" is included in part 2.1.1		
Austin Energy		The standard drafting team may consider adding the sentences in footnotes 2 & 3 directly to section 4.2 Facilities to avoid potentially unnecessary complexity. Also in section 4.2 Facilities, the term bulk power system (BPS), not BES is used. Would use of BES instead of BPS remove the need for footnote 2 without changing the overall intent of the SDT?
Response: We appreciate your thoughtful comments. Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term. The SDT also removed Footnote 2. The SDT believes that the standard is more readable by placing the information pertaining to capacity factor in the footnote.		
Consolidated Edison Co. of NY, Inc.		Use of terms Bulk Electric System (BES) in the purpose and bulk power system in the Applicability section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**

Organization	Yes or No	Question 5 Comment
		Requirement 2: o R2.1.1: requires that model results must "match" results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be some stipulated allowed tolerance band. We suggest that a tolerance is a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the buss voltage being controlled. **The draft standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model.** o The units "point of interconnection" is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term "point of interconnection" may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the buss controlled by the generator excitation system. **Specific reference to point of connection is removed from Requirement R2, Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."** The Applicability Section of the Standard, Section 4.2 permits exclusion of generators with a low capacity factor (< 5%). Why should the Standard allow an exemption for low capacity factor units? The objective of the Standard is to develop good excitation models for dynamics simulations, which are often conducted under high

Organization	Yes or No	Question 5 Comment
		load conditions. At higher loads, these lower capacity factor units are frequently needed and operating. Therefore the Standard should apply to even lower capacity factor units. **The increase in excitation control system model verification is expected to result in improved accuracy of stability based security assessments. The SDT does not believe un-verified data is necessarily inaccurate or that the overall stability of the system is sensitive to that data. The excitation information from the generating units with a 5% capacity factor or less, as provided per standards MOD-012 and MOD-013, is included in the models used to analyze the system under various conditions. Even if these low capacity factor generating units are verified, the accuracy of the simulation is not guaranteed because there are other significant assumptions involved in simulation results, such as load models. As such, the verified models do not provide absolute accuracy under operating conditions other than those conditions for which verification is performed.** Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. **The periodicity information included in Attachment 1 is referenced in Requirement 2, "...in accordance with the periodicity specified in MOD-026 Attachment 1". The attachment table format is being used because the SDT believes that it is the clearest way to present the periodicity information.** Note, there is an entire page of technical references included in the Standard (section G). It is not clear why this is necessary, as the references are described as "beyond the scope of this Standard". **The references are industry documents related to excitation systems. They are provided as a courtesy only because the SDT believes they will be helpful to some users. The referenced documents are not required reading nor are they required for compliance with the standard.**

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Please see responses above.		
Northeast Power Coordinating Council		Use of the terms Bulk Electric System (BES) in the Purpose and bulk power system in the Facilities Section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** In the Applicability Section under the Introduction, the bullets under 4.2.1.2 are unnecessary. The wording of 4.2.1.2 already covers what the bullets detail. **The SDT has refined section 4.2.1.2 of the Facilities section under** **Applicability to provide added clarity.** Regarding Requirement 2: o R2.1.1: requires that model results must "match" results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be a stipulated allowable tolerance band. Suggest that a tolerance be a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the bus voltage being controlled. o R2.1.1: A unit's "point of interconnection" is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term "point of interconnection" may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the bus controlled by the generator excitation system. **Specific reference to point of interconnection is removed from Requirement R2 Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."**

Organization	Yes or No	Question 5 Comment
		Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. **The periodicity information included in Attachment 1 is referenced in Requirement 2, "...in accordance with the periodicity specified in MOD-026 Attachment 1". The attachment table format is being used because the SDT believes that it is the clearest way to present the periodicity information.** Why are the References listed in Section G included? They are described as being "beyond the scope of this Standard". **The references are industry documents related to excitation systems. They are provided as a courtesy only because the SDT believes they will be helpful to some users. The referenced documents are not required reading nor are they required for compliance with the standard.** The language for R4 should be reworded as follows: "R4. Each Generator Owner shall provide revised model data or plans to perform model verification7 (in accordance with Requirement R2) to its Transmission Planner within 180 calendar days of prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response8 characteristic." **The SDT drafted the standard recognizing the model verification requires expertise and calendar time. The model cannot be verified until the actual equipment is installed. While 180 days is the maximum time period that can be utilized to be deemed compliant, it should be recognized that in the vast majority of cases, the personnel that implement the excitation control and plant volt/var control function modifications would also perform testing of the new equipment including staged tests leading to a new model. As such, it would be expected that the final model would be submitted well before the 180 days afforded for compliance.** The way the language is currently written, the generator has to provide its revised model data or plans to perform model verification within 180 days of making the change. For up to 180 days after a change has been made the correct data still may

Organization	Yes or No	Question 5 Comment
		not have been made available to the Transmission Planner. This could have a significant impact on reliability. **The SDT drafted the standard recognizing the model verification requires expertise and calendar time. 180 days is the maximum time period that can be utilized to be deemed compliant. It is expected that all entities will strive to verify the model as quickly as practical.** The suggested rewording addresses this possibility. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs. What is the definition of Gross Nameplate Rating as used in the Standard? **The gross nameplate rating in the applicability of the standard is not capitalized. The gross nameplate rating refers to generator nameplate ratings.**
Response: Thank you for your comment. Please see responses above.		
Southern Company		We agree that the collection of preliminary excitation control system model data from the equipment manufacturer is outside the scope of this standard. Also, any pre-COD staged testing to collect equipment responses to be used to verify the model can be required via Interconnection Agreements. It is understood that any equipment responses collected through pre-COD staged testing with final equipment settings in place that is subsequently used for model verification per the Requirements in the standard would result in fulfilling the requirements for model verification for the next 10 years per the Periodicity Table or until a special circumstance occurs leading to an earlier model re-verification as detailed in Requirements R3, R4, R5, or R5. The limitation to allow sisterhood for only those units at the same physical location should be extended to all identical units for the same GO/GOP - a sister is a sister is a sister. The GO should be allowed to take credit if he can show that the physical location is not a factor in the comparison.

Organization	Yes or No	Question 5 Comment
		The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary. In section 4.2.1.1, and other places, we don't understand the use of "bulk power system" -shouldn't this be "Bulk Electric System". **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.** In 4.2.1.2, second bullet, eliminate the word "comprised" as it is redundant with "consisting". The same redundant use of "comprised" is in section 4.2.2.2 and 4.2.3.2, second bullet. **Section 4.2.2 of the Facilities section under** **Applicability has been revised and the word "comprised" has been deleted.** In R2.1.4, the intended information is not clear - the closed loop voltage regulator part is not needed - it is part of the previous wording. In R2.2, replace "For plants" with "For applicable plants". Please add "where applicable" each time the "plant volt/var control" is used. **The SDT believes that the "closed loop voltage regulator" verbiage is needed to convey technical intent. Please note that at the beginning of the "Facilities" section, there is a phrase "For the purpose of this standard, the following Facilities are considered, "applicable units".**

Organization	Yes or No	Question 5 Comment
		Due to R5, the Planning Coordinator should be listed in the 4.1 Functional Entitles. **The reference to Planning Coordinator has been changed to Transmission Planner to be consistent with the Applicability section of the standard and to conform to NERC functional model.** R5 is confusing - the bullet items list what the GO response should include, but the sentence is written such that the list is what the model review must include. **The main body of the requirement includes the phrase right before the bullets "….that includes one of the following" which re-affirms that the one of the bullets is necessary.** In R2.1.1, please insert "or voltage at the generator terminal" to "at unit's point of interconnection". **Specific reference to point of connection is removed from Requirement R2 Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."**
Response: Thank you for your comment. Please see responses above.		
ACES Power Marketing Standards Collaborators		We continue to believe that this standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. This is the purpose of the FFT process that NERC initiated and FERC recently approved. Interestingly, within the approval order, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one

Organization	Yes or No	Question 5 Comment
		requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard and the problem with attempting to memorialize the cooperation that must occur between the Generator Owner and Transmission Planner to model the generator's excitation and volt/VAr control functions accurately. Requirement R3 allows a Generator Owner to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems cannot be left unsolved. It should be struck. **Requirement R3 is a "peer review" type requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process was over whelming supported by Industry based on their responses in prior postings.** We are not convinced Requirement R4 is needed. **Requirement 4 specifies the need for model verification due to changes to the excitation control system and plant volt/var control function that alter the equipment response characteristic. Without Requirement R4, there would be no trigger between the standard 10 year periodicity to update the model to reflect changes to the excitation system.** The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would

Organization	Yes or No	Question 5 Comment
		not ever apply to the situation of applicable control system changes. **Requirement R4 specifies the need for model verification due to changes to the excitation control system and plant volt/var control function that alter the equipment response characteristic. Attachment 1 addresses the required periodicity and acceptable time delays to remain compliant.** For Requirement R5, there is no clarity for how soon the Generator Owner has to address the model concerns communicated by the Planning Coordinator. If the Generator Owner has the unit in its 10 year plan to test their generation fleet's control systems, they could simply communicate that plan which might be much longer than the Planning Coordinator intended. The drafting team needs to provide more guidance on whether the Generation Owner is expected to accelerate their plans for the unit in question by the Planning Coordinator and by how much. **The intent of the Requirement R5 is for Transmission Planners to use technical justification for validating models for units that meet NERC registry criteria but did not meet applicability threshold of the standard. The Generator Owner has 90 days from the receipt of a request to review and respond to the Transmission Planner's request. If the need for validation is agreed by Generator Owner, the Generator Owner has one calendar year from the date of submitted verification plan to complete validation.** For Requirement R5, who decides if the request is technically justified? Could the Generator Owner simply choose not to respond because they do not believe the request is technically justified? **The technical justification for a request is described in Footnote 4 on page 4 of the standard. However, Generator Owner can in writing challenge any findings of the Transmission Planner within 90 days of the request.** In the Background Information section of the comments, the drafting team indicated that the "standard is drafted to provide the proper cost/benefit balance for performing generator verification". Since the summaries of field test results posted

Organization	Yes or No	Question 5 Comment
		with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit and that does not even include opportunity costs from lost energy sales should the test cause the unit to trip, we believe it would be helpful for the drafting team to provide information on the cost/benefit that was discussed in the Background Information section of the comment form in the next posting. **The stance of the SDT concerning the proper cost/benefit balance was a result of the field test initiated by the Phase III-IV SDT. The field test involved participants from 4 regions including WECC, SERC, ERCOT, and MRO, and was conducted in 2006 to the summer of 2007. The final report is available on the NERC website. At the final face to face meeting of the Field Test, it was concluded by those in attendance that performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations – but at the same time, everyone recognized that there is a monetary cost associated with verifying the models. The SDT believes that these applicability thresholds proposed in the draft standard is in support of the desire of the field test participants in that model verification will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Also, it should be noted that industry experience has proven that the possibility of a unit trip during these tests is extremely low. If ambient monitoring is utilized, the risk is even lower as the collection of data is entirely passive.** The response to our comments regarding consideration for early compliance from the last posting was not satisfactory. In our comments we stated that we appreciated the drafting team's consideration to allow for early compliance based on past tests. However, we stated concerns regarding how to demonstrate this compliance because a registered entity was not required to retain documentation and may not be able to prove they completed a test. The drafting team responded that demonstration of compliance was beyond the scope of the drafting team. While

Organization	Yes or No	Question 5 Comment
		we agree demonstration of compliance for specific companies and situations are likely beyond the scope, demonstration of compliance in general is never beyond the scope. Drafting teams must write standard requirements with which can be complied. Given that the issue of evidence retention from before the effective date of the standard was one of the key subjects in the High-level review conducted by NERC for CAN-0008 recently at the request of the Trade Associations, we suggest the drafting team should consult the appropriate NERC subject matter experts to determine how to avoid these similar issues with this draft standard. **The verbiage for consideration for early compliance is, in part: "The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification". The SDT believes that this conveys the intent that documentation required by those "regional policies, guidelines or criteria existing at the time of model verification" would constitute sufficient proof for early compliance.** Sections 4.2.1.2, 4.2.2.2, and 4.2.3.2 are confusing and potentially contradictory. First, these sections state that they apply to each generating plant/Facility greater than 100, 75 and 50 MVA respectively. Then, the second bullet under each of these sections applies to generating plant/Facility. How can there be a plant within a plant? **The SDT has removed the term "Facility from applicability section of the standard, except one time to clarify the use of the term "applicable units" throughout the standard.** With the first bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 50 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for individual generating units than section 4.2.1.1, 4.2.2.1, and 4.2.3.1

Organization	Yes or No	Question 5 Comment
		which apply to individual generating units. For example, 4.2.2.1 applies a 75 MVA threshold to an individual generating unit and then the first bullet of section 4.2.2.2 applies a 20 MVA unit threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. **The SDT has refined the aforementioned sections in the Applicability section to address your stated concerns.** The NERC Glossary of Terms uses a generator as an example of a Facility. In the second bullet under each segment, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. **The SDT has removed the term "Facility from applicability section of the standard, except one time to clarify the use of the term "applicable units" throughout the standard.** The VRFs simply do not meet the NERC definitions for anything greater than Lower. Requirements R2 and R6 are written with Medium VRFs. All other requirements have Lower VRFs. Neither Requirement R2 nor R6 could be construed as affecting the electrical state or capability of the Bulk Electric System or the ability to monitor, control or restore it. Per NERC definition of Medium VRF, these are prerequisites for meeting a Medium VRF. For Requirement R1, the VRF justification for FERC Guideline 5 refers to the requirement having a high risk objective. This is not consistent with a Lower VRF. We agree with the Lower VRF and recommend removing the "high risk objective" language. **The language in the VRF Guidelines document for a Medium VRF is:** **Medium Risk Requirement** **A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under**

Organization	Yes or No	Question 5 Comment
		emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. **The language in the VRF Guidelines document for a Lower VRF is:** **Lower Risk Requirement** **A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.** **Requirement 2 requires that the Generator Owner "provide, for each of its applicable units, a verified generator excitation control system and plant volt/var control function model…" Model verification is not an administrative task. It requires physical verification of actual system responses. R6 requires the Transmission Planner to notify the Generator Owner whether or not the model that was provided is useable. This links directly with the verification process and has an equal impact to the validity of the model.** All of the measurements use language that sounds like it is creating a new a requirement and is not consistent with language used in any other NERC standard. They all use "must include".

Organization	Yes or No	Question 5 Comment
		The SDT believes the measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. It should be noted that this is consistent with NERC guidelines and support documentation for drafting Standards. It is more typical to use “shall demonstrate”, “shall make available”, etc. These measurements should be made consistent with other NERC standards. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. **The SDT believes the measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. It should be noted that this is consistent with NERC guidelines and support documentation for drafting Standards.** Some examples of the proof include dated postal receipts, dated confirmation of facsimile, etc. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. **The examples were offered as such: these are examples. The SDT understands that the different regions and different entities will have their specific protocols for the requirements associated with NERC Standards. As such, these methods and examples are just to illustrate the flow of information, as the SDT perceives it. These methods and examples are not part of the Requirements, but listed in the Measures. Once again, the methods listed in the Measures are for reference, but are not intended to be an exhaustive and comprehensive list of the possible ways in which this could be implemented.** The Compliance Enforcement Authority section is not the latest approved language

Organization	Yes or No	Question 5 Comment
		being used by NERC. In the data retention section, there is no length of time given for how long a Generation Owner must retain information for Requirement R2 and its associated measurement. **The data retention section for Requirement R2 requires that they keep the latest model verification evidence.** The High and Severe VSLs for Requirement R5 need to be updated. They still refer to Subparts 5.2 and 5.3. The Subparts have been changed to a bulleted list which means they are options. Thus, missing one and meeting the other is full compliance and not partial compliance as the VSLs suggest. **Based on your comment, the SDT has revised the verbiage for the High VSL to not include any references to the sub bullets in Requirement R5, and revised the verbiage for the Severe VSL to include " OR The Generator Owner written response failed to indicate one of the sub bullets of Requirement R5."** We suggest the drafting team write a brief paragraph at the beginning of the Reference section to explain the inclusion of the References. Currently, it states that those references contain technical information that is out of scope of the standard. If so, what is the purpose of including them? We are not against including them but just believe a short explanation for their inclusion is necessary. **The references are industry documents related to excitation systems. They are provided as a courtesy only because the SDT believes they will be helpful to some users. The referenced documents are not required reading nor are they required for compliance with the standard. The statement used to introduce the references is consistent with that used in other standards.** The verification periodicity for row 3 in Attachment 1 needs to be updated from 356 days to 365 days. Furthermore, the drafting team should consider using a year to account for leap years. Otherwise, every four years we are shifting the compliance date up by one calendar day. **We have corrected the typographical error to say "365 days." The SDT believes**

Organization	Yes or No	Question 5 Comment
		that the use of "365 days" instead of "one year" is more appropriate and consistent with the use of "180 days" elsewhere in the standard.
Response: Thank you for your comment. Please see responses above.		
PSEG		We have these additional comments: a. The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states "Synchronous condensers are not currently addressed in the NERC Registry Criteria" However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency. **The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.** b. The entire section 4.2 has language that includes "directly connected to the bulk power system." The BES is a subset of the BPS (per Order 743), and the GVSDT should consult with the SDT for Project 2010-17 - Definition of BES - to develop alternate language that instead refers to the BES. **Based upon your comments and others, the SDT replaced references to the BPS with references to the BES which is the NERC defined term.**
Response: Thank you for your comment. Please see responses above.		
ISO New England Inc		We suggest that the language for R4 be made more clear and state as follows."R4. Each Generator Owner shall provide revised model data or plans to perform model verification5 (in accordance with Requirement R2) to its Transmission Planner 180

Organization	Yes or No	Question 5 Comment
		calendar days prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response6characteristic. The way the language is currently written, the generator merely has to provide its plans for model verification. This means that 6 months after a change has been made, the correct data still may not have been made available to the Transmission Planning. This could have a significant impact on reliability. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs.
Response: The SDT thanks you for your comment. The SDT drafted the standard recognizing the model verification requires expertise and calendar time. The time frames mentioned in the comment are the maximum time periods that can be utilized to be deemed compliant. It is expected that all entities will strive to verify the model as quickly as practical. The model representing the new equipment cannot be verified until the new equipment is installed. Also, this standard addresses model verification, not the submittal of preliminary design models.		
Southern California Edison Company		While an active closed-loop voltage regulation function is useful in distinguishing transient voltage and frequency responses within mere cycles or seconds of perturbations, a similar requirement should be added to MOD-026-1 to require variable generators who were exempted from the standard by the condition added to Attachment 1 to provide similar plant voltage/var control, design, and test data to the Transmission Planner. The automatic switching of capacitor banks and reactor banks can play a role in maintaining the voltage stability of the system.
Response: The SDT thanks you for your comment. The intent was not to give an exemption to any unit or plant that has a closed loop voltage regulation function. If a plant has a device that provides dynamic voltage regulation (such as a STATCOM, DVAR or SVC, and perhaps automatically controlled capacitors commonly found in Renewable Plants), these devices should be included in the model and should be validated. If the automatically controlled (mechanically switched) capacitor bank is in whole or a part of the primary dynamic volt/var response of the plant, it should be modeled and validated. Both PSS/e and PSLF have standard library models to represent automatically switched capacitor banks (SWSHNT in PSS/e and MSC1 in PSLF). Ultimately, the local		

Organization	Yes or No	Question 5 Comment
interconnection requirements should be used to determine if the automatically controlled capacitor banks are a primary means for dynamic volt/var regulation within any particular application. Based on review of a plant's application requirements, the testing /validation entity should determine if the automatic capacitor bank should be validated. Please reference Row 6 of Attachment 1 of the current draft of the standard.		
Exelon Corp.		Draft MOD-026-1 R.2.1 requires that the Generator Owner perform verifications subject to include certain information as specified in sub requirements 2.1.1 through 2.1.6. R 2.1.1 requires that the unit model response is matched to the recorded response for a voltage excursion at the "point of interconnection". For certain generating units the "point of interconnection" is on the high voltage side of the main power transformer (i.e., the switchyard disconnect switch). Because of this, the model would have to consider the impact of the main power transformer, auxiliary transformer, and auxiliary transformer loads all of which are not part of the generator/excitation system model. The Standard should be revised to state the response of interest is at the generator terminals and not at the "point of interconnection." **Specific reference to point of connection is removed from Requirement R2 Part 2.1.1. Language has been modified to: "Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance."** Typically individual synchronous machines have generator excitation control systems and do not have volt/var control systems. The text "and / or" or "as applicable" should be added to all references to "volt/var model" in the Standard and the associated attachments. **Based on your and other industry comments, the SDT modified the phrase "generator excitation control system and plant volt/var control functions" to "generator excitation control system or plant volt/var control functions" to recognize that the use of the phrase "or" is technically correct the vast majority of the time.**

Organization	Yes or No	Question 5 Comment
		With respect to the SDTs response to Exelon's comment regarding the lack of acceptance criteria (refer to MOD-026-1 Consideration of Comments dated 2-23-12 pp 89-90), the following statements by the SDT need to be more clearly articulated within the body of the Standard. **"It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response."** The current draft (draft 3) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not "usable", if there are technical concerns with the verification documentation, or if the model response did not match an actual event. This written response is to contain either plans for performing model verification, model changes or a technical basis for maintaining the current model. It appears from the comments of the SDT (see question 3 above) that the Generator Owner has final say on the model; however, if the opinion of the Transmission Planner differs from that of the Generator Owner there is the potential for a disagreement between the two entities. Given the potential for a dispute to occur and the lack of an "acceptance criteria" the SDT should consider adding in a provision for dispute resolution between the parties or clearly delineate that the GO has the final say. **The SDT believes that the draft Requirement clearly conveys that the GO has the final say as the draft standard does not list any additional processes. The SDT also believes that both parties will be equally motivated to resolve any technical issues with the model.**
Response: Thank you for your comment. Please see responses above.		

Organization	Yes or No	Question 5 Comment
Puget Sound Energy		None

PRC-024 Overall Summary Consideration: The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

A slight majority of stakeholders were in agreement with the approach taken for Requirement R4. Of the stakeholders who did not agree with the approach, the reasons most often cited were that such estimates would not provide any reliability benefit, the estimates are difficult to calculate, and the time period allowed to respond to a request for an estimate (60 days) is too short. The SDT modified the structure of the requirement to clarify the intent and the limits of what entities could request a performance estimate, but did not change the time period allowed to respond.

A large majority of stakeholders indicated that they did not agree that it is technically achievable for new generation to meet the performance required in Requirement R5. The most common reason stated was that Attachment 1 did not correctly specify the WECC region underfrequency tripping limits. Other objections cited by more than one responder were that the curves in Attachments 1 and 2 are too stringent, that significant R&D work needs to be done on the design of a plant to meet the requirement, and that the cost of building such a plant would be too high with little corresponding gain in grid reliability. The SDT corrected the error in the Attachment 1 underfrequency curve and data table for the Western Interconnection. The SDT did not make any substantive changes to Requirement R5 since the SDT did not feel stakeholders presented valid arguments that the requirement could not be achieved technically, given that similar requirements are already in effect in other parts of the world.

Other specific revisions to the standard are:

- **The wording in Requirement R1 was revised for clarity, Part 1.1 (rate of change of frequency) was removed and new Parts 1.2 and 1.3 were added for consistency with Requirement R2 at the request of several stakeholders.**
- **Minor changes in the wording in Requirement R2 were made to improve clarity at the request of several stakeholders.**
- **The structure of Requirement R4 was modified and minor wording changes were made to improve clarity at the request of several stakeholders, though no changes were made to the intent of the requirement.**
- **Part 5.1 and Subpart 5.1.1 were incorporated into the body of Requirement R5 so that the remaining Parts of this requirement describe exceptions (i.e. allowances to trip).**
- **Minor wording changes were made at the request of multiple stakeholders to clarify wording in Parts 5.1 – 5.6 of Requirement R5.**

- **The allowable time to respond to a request for generator protection settings in Requirement R6 was increased from 30 days to 60 days at the request of several stakeholders.**
- **The Violation Risk Factors for Requirements R1, R2, and R5 were changed from High to Medium at the request of several stakeholders.**
- **Minor wording changes were made to Measures M3, M4, and M5 were made for clarity at the request of several stakeholders.**
- **The time frame referenced in Measure M6 was modified to correlate with the change made in Requirement R6.**
- **The wording in the Data Retention section was revised at the request of one stakeholder and now reflects the wording used in other recently-approved standards.**
- **Minor changes were made in the VSL's for Requirements R1, R2, R3, and R4 to add clarity or correct errors mentioned by several stakeholders.**
- **The wording in the Severe VSL for Requirement R5 was revised to add a reference to Parts 5.1 – 5.6 and the tardiness levels in the Requirement R6 VSL's were revised to reflect the change in the requirement.**
- **The underfrequency curve for the Western Interconnection and corresponding data table were corrected in Attachment 1 at the request of many stakeholders in the WECC region.**
- **Curves for the ERCOT Interconnection and a corresponding data table were added to Attachment 1 at the request of ERCOT.**
- **The term "base voltage" was replaced with "nominal operating voltage" in Clarification #1 to Attachment 2 at the request of several stakeholders.**
- **Minor wording changes were also made to Clarifications #2, and #5 to better convey the intent of the SDT in response to questions presented by several stakeholders.**

6. **Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language.**

Summary Consideration: A slight majority of stakeholders were in agreement with the approach taken for Requirement R4. Of the stakeholders who did not agree with the approach, the reasons most often cited were that such estimates would not provide any reliability benefit, the estimates are difficult to calculate, and the time period allowed to respond to a request for an estimate (60 days) is too short. The SDT modified the structure of the requirement to clarify the intent and the limits of what entities could request in a performance estimate, but did not change the time period allowed to respond.

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator	Negative	Requirement R4 asks owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This estimate is difficult to provide with sound technical basis, and may not contribute to any more valid assessment of a generator's expected performance than a TP's conservative assumptions drawn from available information already provided by the GO and the standard's Attachments 1 and 2. In brief, this requirement does not appear to provide any reliability benefit at all.
Response: Thank you for your comments. The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving

Organization	Yes or No	Question 6 Comment
		of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner or Transmission Operator. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, from the GO which then can accessed by any impacted Registered Entities.
Response: Thank you for your comments. Planning Authority is no longer used in the current NERC Functional Model; the functions are now assigned to the Planning Coordinator, which is included in Requirement R4. The SDT believes that the Balancing Authority typically does not do long-term planning studies, but if the BA were interested in the performance estimate, he could work with the Transmission Operator or Transmission Planner to obtain the information.		
Wisconsin Electric Power Co., Wisconsin Electric Power Marketing	Negative	Requirement R4 is not reasonable since it is difficult to provide any meaningful estimate of performance during frequency excursions. **The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. In addition, the SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.** Also, the No Trip curve in Attachment 2 needs further clarity, especially when the Generator Owner has voltage relaying that is connected to VT's on the low-side of the GSU. **The SDT agrees that generator protection normally senses the voltage at the**

Organization	Yes or No	Question 6 Comment
		generator terminals. Because there are many configurations of the connections of the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661-A and other international grid standards that are in effect.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Wisconsin Energy Corp.	Negative	PRC-024-1: Requirement R4 is not reasonable since it is difficult to provide any meaningful estimate of performance during frequency excursions. The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. In addition, the SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, “Detailed unit performance studies are not required to develop the estimate.” The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. Also, the No Trip curve in Attachment 2 needs further clarity, especially when the Generator Owner has voltage relaying that is connected to VT’s on the low-side of the GSU. The SDT agrees that generator protection normally senses the voltage at the generator terminals. Because there are many configurations of the connections of

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		the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661-A and other international grid standards that are in effect.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Texas Reliability Entity	No	Most existing facilities are likely not designed to a frequency or voltage ride-through standard, and a useful estimate may be very difficult for owners to provide. Generator Operators may be able to document "known" equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation.
Response: Thank you for your comments. The SDT agrees that most existing facilities are not designed to ride through a voltage excursion created by a three-phase fault at the plant substation. The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request. In addition, the draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Exelon Corp.	No	The Frequency/Voltage Excursions should be limited to those listed in the standard, this should be explicitly stated in the requirement. 60 calendar days is an unreasonable amount of time to perform a study of this magnitude, suggest increasing the amount of time perform this study.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. The SDT believes there is value in allowing the estimate of performance for a voltage excursion specific to particular facilities (which would be less stringent than the curves in Attachment 2). The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.		
ACES Power Marketing Standards Collaborators	No	This requirement will essentially be redundant with standards MOD-026 and MOD-027. MOD-026 already requires the Generator Owner to verify its excitation and volt/VAr control systems. MOD-027 already requires the Generator Owner to verify its frequency response and its turbine/governor, load control and active power/frequency control models.
Response: Thank you for your comments. The SDT disagrees that this requirement is redundant with MOD-026 and MOD-027. Those standards require Generator Owners to verify the response of the excitation system (MOD-026) and frequency control system (MOD-027) to disturbances, but do not address the ability of a generating unit to ride through excursions.		
MRO NSRF	No	Since most existing facilities are likely not designed to a frequency or voltage ride-through standard, the estimate may be very difficult for owners to provide. Staged testing would not be practical for making this determination and engineering analysis may not have the accuracy to make it useful for use by Transmission Planners.
Response: Thank you for your comments. The SDT agrees that most existing facilities are not designed to ride through a voltage excursion created by a three phase fault at the plant substation. The SDT does not require Generator Owners to do extensive dynamic simulations or staged testing to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor dropout or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it is requested by a		

Organization	Yes or No	Question 6 Comment
planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations	No	Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of predicting responses to voltage and frequency excursions. This is especially the case when one must, per R4.1, engage in the phenomenal complexity of calculating the transient performance of auxiliary buses and identifying the short-term drop-out thresholds of the multitudinous pieces of equipment they power. The references in R4.1 and 4.2 to experience, actual event histories or sound engineering judgment as alternatives to a computer model are not helpful, because meaningful assessments can be made only if one has relevant data (i.e. high-speed records of past disturbances, at HV, MV and LV voltage levels) and issue a PV. Further on the subject of complexity, there are a variety of aux bus configurations possible for our multiple-unit plants, any one of which could be deemed normal depending on circumstances. Having to check every aux bus configuration for every units-running combination would be unduly burdensome, even if it were possible. The fact that R4 cites “Frequency/Voltage Excursions” (apparently meaning simultaneous deviations of these parameters), while R5 is careful to refer to “frequency excursion or voltage excursion,” adds confusion. Another concern is that the boundary conditions for the above-described analysis are presently undefined, with the standard invoking instead a “dynamic simulation provided by the Transmission Planner.” For the reasons stated above, the proposed requirement R.4 should be eliminated.
Response: Thank you for your comments. The SDT did not intend that the Generator Owner have to estimate performance during simultaneous voltage and frequency excursions and has revised the wording in Requirement R4 to say, “…frequency or voltage excursion…” The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, “Detailed unit performance studies are not required to develop the estimate.” The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners		

Organization	Yes or No	Question 6 Comment
regarding the performance of generating facilities during frequency and voltage excursions.		
Luminant Power	No	An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions.		
Arizona Public Service Company	No	This type of data is not going to result into any more accurate simulation than the existing methodology which does not include this data. There are many other inaccuracies involved in modeling and scenario planning for islanding studies. It is a misconception that just by having more complex modeling will improve accuracy and thus reliability.
Response: Thank you for your comments. The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.		
Southern Company	No	We cannot agree with the approach of Requirement R4 due to the uncertainty about how to estimate the performance of "each" plant system, sub-system, or

Organization	Yes or No	Question 6 Comment
		component that could cause the unit to trip for the voltage excursion profile of Attachment 2. For most units, this estimate may vary from a few cycles (examples: dropout of low voltage motor contactors or an auxiliary control relay) to up to 1-2 seconds (examples: tripping of boiler controls or medium voltage motors). Determination of a more accurate time estimate would require detailed dynamic analysis, which would entail significant engineering study and involve assumptions and judgment based on experience. Data from actual event histories, if available, would likely not match all points of the Attachment 2 time-voltage profile. The voltage excursion profile needed for an evaluation would be the voltages present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. Without detailed analysis, only a rough estimate could be made which would probably be of limited value for transmission system analyses. A conservative approach would be the "go/no-go" approach and identify those units that are likely to trip for a specified voltage excursion. For the current requirements stated in R4, the 60 day time requirement would be a significant challenge for a GO to meet for a single unit. For GOs who have a large number of units and limited engineering resources, the 3-year phase-in period will be impractical to establish on many units the estimated performance of "each" plant system, sub-system, and component that could trip. Bottom line is, the concept may seem simple enough in principle, but these requirements cannot be practically met. We believe the scope of the standard should be limited to identification of the protection function trips per R1, R2, R3, and R6 only.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset (similar to the go/no go methodology suggested). While it is possible that a Transmission Planner could request a performance estimate for all of a Generator Owner's units over the implementation period (which has been revised from three years to five years), the SDT feels the Transmission Planner would be more likely to only request the information for generators more critical to system stability. The SDT was charged with meeting the recommendations of FERC		

Organization	Yes or No	Question 6 Comment
Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions.		
AECI	No	My concern with this requirement is that if a GO provides an estimate of how long they believe that the unit can ride out the event, then what will happen if they do not make this target? Will the GO be held responsible for not making this time? Due to this concern how accurate are these times that are provided by the GO going to be and how much will be a built in cushion?
Response: Thank you for your comments. There is no language in Requirement R4, Measure M4, or the associated VSL that indicates there would be any penalty to the Generator Owner if an excursion occurred and a generating unit did not perform as estimated.		
We Energies	No	It is very difficult to estimate generator performance during frequency or voltage excursions, especially frequency, and the best efforts to provide an estimate may not provide a meaningful result. It is proposed that the TO or TP could achieve the objective better by tracking transmission system voltage/frequency events that could have resulted in abnormal voltages at generating stations, and work cooperatively with the GO informally to determine the generator performance.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations. The process suggested in your comment would be one method of estimating the generating unit performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Manitoba Hydro	No	More detail is required in R4 to ensure that the Transmission Planner can model behavior before and after the disturbance. Information should be provided on how long the unit should take to ramp back to full power following a voltage or frequency excursion that doesn't cause the unit to trip.
Response: Thank you for your comments. The SDT believes it the uncertainties involved in trying to determine generator outputs		

Organization	Yes or No	Question 6 Comment
and ramp rates would not improve grid reliability.		
Independent Electricity System Operator	No	As indicated in our previous comment, we do not support having a requirement to obtain such an estimate. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2 and Requirement R3 and the information already received, a TP can apply the following relevant assumptions to its planning studies: i. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip;ii. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be more valid than applying the conservative assumption "b" above. We cannot envisage a Transmission Planner to use this additional information if this information cannot be ascertained to be more valid. In short, we do not believe provision of this estimate will provide any more valid assessment of a generator's expected performance than a TP's conservative assumptions drawn from available information already provided by the GO and Attachments 1 and 2. The estimate does not provide any reliability benefit at all.We suggest the SDT remove this requirement altogether.
Response: Thank you for your comments. The SDT appreciates your position, but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during		

Organization	Yes or No	Question 6 Comment
frequency and voltage excursions. This requirement is written such that the information is only provided if it requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration believes that this is an open-ended requirement that allows multiple planning and operations entities - not just Transmission Planners - to require complex assessments completely at their discretion. There is no allowance for the availability of GO resources nor any need for the requestor to provide a reliability justification. Furthermore, we would like to point out that the modeling validation requirements of MOD-027-1 (frequency) and MOD-026-1 (voltage) must, by definition, include the impact of protective relay settings. This means that a need for an estimate of performance is not necessary as real performance data will always be available. In addition, these Standards already allow recourse for a re-validation if Transmission Planners cannot reconcile their models with actual generator performance.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT disagrees that MOD-026 and MOD-027 evaluate voltage and frequency protection functions. Those standards require Generator Owners to verify the response of the excitation system (MOD-026) and frequency control system (MOD-027) to disturbances, but do not address the ability of generator protection or a generating unit to ride through excursions.		
Luminant Energy	No	An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required		

Organization	Yes or No	Question 6 Comment
to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset (similar to the go/no go methodology suggested). The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. The SDT cannot remove the requirement without replacing it with another method of giving the Transmission Planner the necessary information.		
Duke Energy	No	Generator Owners don't currently have the capability to provide this information, and will need time to obtain the capability and perform the studies. Requirement R4 should be removed from Effective Date sections 5.1, 5.2 and 5.3 because one, two or three years is insufficient time. R4 should have its own effective date section specifying an effective date of the first day of the first calendar quarter five years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter five years following Board of Trustees adoption. Requirement R4 should also be revised to allow the Generator Owner 180 days (instead of 60 days) to respond to a request and provide an estimate of a unit's performance during frequency/voltage excursions.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance so has not extended the time period for responding to a request for the estimate. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT agrees with the suggestion to change the implementation period to five years.		
Ameren	No	At the end of R4.2, we suggest to add "the Transmission Planner's voltage recovery characteristic from R2 part 2.1.1" since that may well have bearing on the estimate. We understand the reasons for such studies, but we ask the GVSDT to consider the fact that more than 60 days may be needed to estimate generating unit performance especially the first time it is done for each unit. As long as this applies only to generator frequency and voltage protective relaying (and not to station auxiliaries)

Organization	Yes or No	Question 6 Comment
		developing these estimates in the time frame mentioned earlier is achievable.
Response: Thank you for your comments. The standard has been modified to require the requesting entity to provide a "…frequency or voltage excursion defined by the voltage or frequency profile at the point of interconnection described by dynamic simulation provided by the requestor (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit)." The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance, so has not extended the time period for responding to a request for the estimate. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Cowltiz PUD	No	Cowlitz is only concerned with the 60-day response time. The responding entity should be given some leeway to negotiate a delivery time if the 60-day response is not feasible. Otherwise, substandard estimates will be provided to avoid violation of the standard.
Response: Thank you for your comments. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance so has not extended the time period for responding to a request for the estimate. The SDT agrees with many commenters that it is not realistic to provide an extremely precise estimate. The quality of the estimate is not specified in the requirement, measure, or associated VSL. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Indiana Municipal Power Agency	No	IMPA does not agree that there would be any gain in reliability by requiring Generator Owners to give an estimate on the performance of a unit or the overall plant during a frequency or voltage excursion. Will such a request include specific parameters that would be expected on the system to narrow down this imposition of an estimate upon the Generator Owner? Will Generator Owners be capable of providing an estimate that may be required under this item? In addition, the Transmission Planner is to provide the dynamic simulation of the voltage and frequency profile at the point of interconnection. There is no guidance in the Standard as to how often or what means will be used to submit the (new) profile(s) to the GO - will it be annually, seasonally or?? IMPA also has concerns with attempting

Organization	Yes or No	Question 6 Comment
		to accurately predict the ride-thru capabilities of a generating unit/plant on a consistent basis. As an example, if the unit/plant was operating during an extreme and prolonged period of heat and humidity it's characteristics and ability to ride thru a frequency and/or voltage event will be different than if running during the opposite - extreme cold and wind. Many of the unit/plant auxiliary systems may be located in areas that are not climate controlled and it would be extremely difficult to consistently predicte how they will react during temperature extremes.
Response: Thank you for your comments. As you note in the comment, the standard requires the requestor to specify the voltage or frequency excursion for which the Generator Owner is to provide an estimate of the time duration the generator unit will remain connected. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance, so has not extended the time period for responding to a request for the estimate. The SDT agrees with many commenters that it is not realistic to provide a precise estimate. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset. While the requirement does not limit the number of requests that may be submitted by a Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner, it also does not prevent the Generator Owner from responding with the same estimate to each request.		
Pepco Holdings Inc. & Affiliates	Yes	Agree in principle with attempting to quantify the ability of the unit (including affect on plant auxiliary systems) to remain connected during voltage and frequency excursions. However, the present wording of this requirement may not result in sufficient information to fully model the performance of the unit in dynamic studies. It may be more constructive to request a modified set of voltage and frequency ride through curves (similar to Attachments 1 & 2) that represent the Generator Owner's best estimate of a no trip zone for each unit, taking into account the performance of plant auxiliary systems, as well as any other protection / control setting, or operational limitation, that would prevent the unit from remaining on line within the no-trip zone as defined in Attachments 1 & 2. This would provide the Transmission Planner with sufficient information to fully model the anticipated performance of the

Organization	Yes or No	Question 6 Comment
		unit in their dynamic studies.
Response: Thank you for your comments. The SDT believes that requiring the Generator Owner to produce a set of curves that define successful performance would require more resources and would not provide any more useful information than the approach currently defined in Requirement R4. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate."		
Xcel Energy	Yes	We agree that the current wording (which removes the requirement to provide a probability of ride through) is an adequate means of achieving the reliability goal.
Response: Thank you for your comments.		
American Electric Power	Yes	AEP agrees with this approach for Attachment 1 only. We also have the following comments about the reference to Attachment 2 in R4. The reliability advantage to be gained from the inclusion of Attachment 2 is unclear, unprecedented and potentially costly. With respect to Attachment 1, any information that a GO can provide about a potential for their unit to trip within the no-trip zone of Attachment 1 will assist the Planning Coordinator in devising a UFLS program for their area, which they are obligated to do under PRC-006-1. A successfully designed UFLS program depends on knowing whether or not generation would trip prior to operation of all stages of UFLS. If it is known that a generator could trip prior to all stages of UFLS, apart from protection settings that would be reported to them under R1 of this standard, the PC ought to know that. Of course, we understand that a GO would not be held accountable under R4 for unknown factors that may result in tripping of their unit within the no-trip zone of Attachment 1. Attachment 1 should be referenced because it would be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the coordination that should take place between UFLS and generation tripping apart from Attachment 1. We also believe reference to Attachment 1 is necessary for consistency in the application of R4 throughout an interconnection. We therefore conclude that it is desirable for overall reliability purposes to reference Attachment 1 in R4. We also point out that

Organization	Yes or No	Question 6 Comment
		curves of the nature of those in Attachment 1 have long existed as guidelines for generation performance during frequency excursions in each of the reliability regions. GOs are familiar with these types of curves, and generating units have been designed with these guidelines in mind. With respect to Attachment 2 being referenced in R4, the reliability advantage is not as clear, but we ask the SDT to consider again that it may be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the possible voltage excursion events that a generating unit may be subject to, and for which it may be desirable to know whether or not a given generating unit would be able to ride through that disturbance. Reference to Attachment 2 may be desirable for, again, consistency in the application of R4 throughout an interconnection. However, in contrast to frequency, voltage is a local quantity and so it is not as critical to system reliability that GOs report voltage excursion trips within the no-trip zone of Attachment 2. The translation of the no-trip zone of Attachment 2 to internal generating plant voltages that would need to be determined is not straightforward, though that translation would need to be made by a GO regardless of whether they would receive point-of-interconnection voltage simulations from a TP or be directed to Attachment 2. We conclude that reference to Attachment 2 in R4 may have reliability benefits that the SDT may want to consider, but we do not believe reference to Attachment 2 is as essential as reference to Attachment 1.If the SDT did not include reference to Attachment 2, that should not have a bearing on the reference to Attachment 1. We assert that, because of the different characteristics of frequency and voltage, it would not be inconsistent to reference Attachment 1 but not Attachment 2.

Response: Thank you for your comments. The SDT agrees that it will be easier for a Generator Owner to estimate generating unit performance for a frequency excursion than to estimate performance for a voltage excursion. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The draft standard has been modified to clarify that, "Detailed unit performance studies are not required to develop the estimate." For a voltage excursion, the SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or

Organization	Yes or No	Question 6 Comment
other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.		
Western Electricity Coordinating Council		I am unsure of the intent of the phrase "estimate of the performance of the units during frequency and voltage excursions." Is this intended to mean that the owners should estimate whether or not the unit will stay connected, or provide some estimate of the unit's dynamic performance and response to an event? I also don't understand the purpose of this requirement. If models already exist and are available to the Transmission Planners, then the owners should be validating the model. As part of the validatio process the owners should be able to tell the Transmission Planner what the performance will be. Is this for units for which models have not been validated?
Response: Thank you for your comments. The wording in Requirement R4 has been revised so that it now states, "…the time duration the existing unit or generating plant or generating Facility will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or voltage excursion…" It is only an estimate of if the unit is expected to ride through the event or to trip. There is no connection between this requirement and the verification of excitation response or frequency response models as defined in Standards MOD-026 and MOD-027.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Standards Development Team	Yes	
Puget Sound Energy	Yes	
Dominion	Yes	
Imperial Irrigation District (IID)	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 6 Comment
GO/GOP		
PacifiCorp	Yes	
Massachusetts Attorney General	Yes	
Dynegy	Yes	
PSEG	Yes	
ISO New England Inc	Yes	
American Transmission Company, LLC	Yes	
South Carolina Electric and Gas	Yes	
GenOn Energy	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Austin Energy	Yes	
Southern California Edison Company	Yes	
Georgia Transmission	Yes	

Organization	Yes or No	Question 6 Comment
Corporation		
American Wind Energy Association	Yes	
Los Angeles Department of Water and Power		LADWP does not have comments on this question at this time.

7. **Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. Please provide along with your comment, what you believe the timeframe is needed to implement this requirement.**

Summary Consideration: A large majority of stakeholders indicated that they did not agree that it is technically achievable for new generation to meet the performance required in Requirement R5. The most common reason stated was that Attachment 1 did not correctly specify the WECC region underfrequency tripping limits. Other objections cited by more than one responder were that the curves in Attachments 1 and 2 are too stringent, that significant R&D work needs to be done on the design of a plant to meet the requirement, and that the cost of building such a plant would be too high with little corresponding gain in grid reliability. The SDT corrected the error in the Attachment 1 underfrequency curve and data table for the Western Interconnection. The SDT did not make any substantive changes to Requirement R5 since the SDT did not feel stakeholders presented valid arguments that the requirement could not be achieved technically, given that similar requirements are already in effect in other parts of the world. The SDT did not feel objections to the cost or lack of reliability benefit could be considered as overriding FERC Order 693.

Organization	Yes or No	Question 7 Comment
Avista Corp.	Negative	The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately

Organization	Yes or No	Question 7 Comment
		reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Balancing Authority of Northern California	Negative	Regarding Attachment for the “OFF NOMINAL FREQUENCY CAPABILITY CURVE” o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. Please refer to the submitted WECC Comments. o Regarding the PRC-024 Attachment I curves, the multiple regional frequency curve overlay is quite busy and difficult to discern. Please consider posting separate curves for the various interconnection. o It is unclear whether or not frequency events that fall on the “line” allow for the generator to trip. For instance the WECC Off-Nominal Frequency Plan allow for instantaneous trip for frequency excursions f ? 57.0 Hz. Please identifying the allowable trip-time values for each interconnection table at the given time delay.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
BrightSource Energy, Inc.	Negative	The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay

Organization	Yes or No	Question 7 Comment
		connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Chelan County Public Utility District #1	Negative	The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. The presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
City of Austin dba Austin	Negative	Regarding Attachment for the “OFF NOMINAL FREQUENCY CAPABILITY CURVE” o

Organization	Yes or No	Question 7 Comment
Energy		Please separate out the drawings for the various interconnection curves so they are not all on one graph. **The SDT feels that the overlay of each variance is beneficial to understanding the differences between the regions. The data tables that follow the graph provide the precise details of each curve.** o Formally state that the “line” in the graph is not included in the No Trip Zone. Currently, the only way to know whether the “line” is in or out is this note on the graph. Regarding the “Curve Data Points:” tables **There is already a statement on the graph that states that the no trip zone does not include the lines.** o Please clarify the Frequency delineation by adding where appropriate or a text description such as “up to and including” or “up to but not including”. **There is already a statement on the graph that states that the no trip zone does not include the lines and the data tables have been reformatted to make this clearer.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
City of Farmington	Negative	FEUS agrees with the comments submitted by WECC: "The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the

Organization	Yes or No	Question 7 Comment
		WECC Coordinated Off-Nominal Frequency Load Shedding Plan."
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
City of Redding	Negative	Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" - The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. - Suggest to separate out the drawings for the various interconnection curves so they are not all on one graph. - Formally state that the "line" in the graph is not included in the No Trip Zone. Currently, the only way to know whether the "line" is in or out is this note on the graph. WECC formally indicates it in their table with the "<" signs.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Clark Public Utilities	Negative	I have voted negative because the PRC-024 criteria for generator frequency ride through and generator voltage ride through are not consistent with current WECC practices and proposals. Regarding frequency, WECC has had its Off Nominal Frequency Plan in place for many years. In addition, Reliability Standard Project WECC-0065 is proposed regional generator frequency ride through plan. Both of those plans use a long existing frequency ride through schedule. PRC-024 as proposed has a frequency ride through that neglects one of the low frequency points in the WECC plans. The 58.4 Hz setpoint (missing in PRC-024) avoids a low frequency area will result in damage to combustion turbines. PRC-024-1 must have a WECC low frequency ride through as follow: 57.0 HZ (0 - 0.75); 57.3 HZ (0.75 - 7.5); 57.8 Hz (7.5 - 30); 58.4 Hz (30 - 180); 59.4 Hz (>180). The overfrequency setpoints in PRC-024 are consistent with WECC practices. **The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has**

Organization	Yes or No	Question 7 Comment
		also been corrected. Additionally, the voltage ride through is confusing. In WECC, generators are supposed to be able to run continuously from 1.10 pu to 0.9 pu. I urge the STD to look at the work in the now terminated WECC-060 standards project (see the document entitled The Technical Basis for the New WECC Voltage Ride). The PRC-024 curve point data table seems to indicate that instantaneous trips are not allowed for 1.20 pu overvoltage. There is no reason for not allowing an instantaneous trip at this high of voltage. The generator will probably trip on overexcitation at this level anyway. The table needs to be informative enough so that if the data points were plotted, the expected curve would result. Looking at the curves it appears the table should read as follows for overvoltage. 1.05 pu (no trip); 1.10 pu (1.0 - 600.0); 1.15 pu (0.5 - 1.0); 1.175 pu (0.2 - 0.5); 1.20 pu (0 - 0.2). To avoid confusion the undervoltage criteria should read as follows. 0.95 pu (no trip); 0.90 pu (2.0 - 600.0); 0.75 pu (2.0 - 3.0), 0.65 pu (0.3 - 2.0); 0.45 pu (0.15 - 0.3); 0.00 pu (0.15). **The SDT acknowledges that certain regions may have more stringent voltage requirements, but does not believe that the standard should require the entire continent to meet the most stringent requirements. The data table for Attachment 2 has been reformatted to make the information clearer**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Colorado Springs Utilities	Negative	The curve depicting the “no trip zone” in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds

Organization	Yes or No	Question 7 Comment
		(or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Consumers Energy	Negative	"Related to undervoltage criteria, the 18 cycle at 45% of generator voltage would put a great deal of strain on the plant auxiliary systems and that may not be something these systems are able to withstand. The same would be true of a fault that produces 65% voltage at the generator terminals for 2 seconds. These comments relate specifically to Consumers Energy. However, it is likely that many others have similar equipment and would have the same issues. Please also note that the proposed standard does not align with ANSI C37.102, IEEE Guide for AC Generator Protection or with the NERC Technical Reference Document entitled Power Plant and Transmission System Protection Coordination." My vote is the same on the non-binding poll.
Response: Thank you for your comments. Please note that the voltage levels specified in Attachment 2 are at the point of interconnection to the transmission system. They would not correlate directly with the auxiliary bus voltages, especially if the auxiliaries are unit-connected. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. Please inform the SDT of the specifics of your concerns.		
MEAG Power	Negative	Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. o We'd like them to separate out the drawings for the various interconnection curves so they are not all on one graph. o Formally state that the "line" in the graph is not included in the No Trip Zone. Currently, the only way to

Organization	Yes or No	Question 7 Comment
		know whether the "line" is in or out is this note on the graph.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Municipal Electric Authority of Georgia	Negative	Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. o We'd like them to separate out the drawings for the various interconnection curves so they are not all on one graph. o Formally state that the "line" in the graph is not included in the No Trip Zone. Currently, the only way to know whether the "line" is in or out is this note on the graph.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Pacific Gas and Electric Company	Negative	The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately

Organization	Yes or No	Question 7 Comment
		reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Portland General Electric Co.	Negative	The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Sacramento Municipal Utility District	Negative	Regarding Attachment for the “OFF NOMINAL FREQUENCY CAPABILITY CURVE” o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. Please refer to the submitted WECC Comments. o Regarding the PRC-024

Organization	Yes or No	Question 7 Comment
		Attachment I curves, the multiple regional frequency curve overlay is quite busy and difficult to discern. Please consider posting separate curves for the various interconnection. o It is unclear whether or not frequency events that fall on the "line" allow for the generator to trip. For instance the WECC Off-Nominal Frequency Plan allow for instantaneous trip for frequency excursions f ? 57.0 Hz. Please identifying the allowable trip-time values for each interconnection table at the given time delay.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		
Seattle City Light	Negative	A) Regarding Attachment for the "OFF NOMINAL FREQUENCY CAPABILITY CURVE" o The WECC ONFLS plan vs. the PRC-024 plan do not match for the low-frequency duration. o Please separate out the drawings for the various interconnection curves so they are not all on one graph. It is difficult to read as presented. o Formally state in the standard that the "line" in the graph is not included in the No Trip Zone. Currently, the only way to know whether the "line" is in or out is a note on the graph. B) Regarding timing of various proposed activities: o Clarify the time given to Generator Owners to document all the equipment limitation that prevents compliance with the proposed Requirements R1 and R2, in reference to Requirement R3. o Provide a timeline on when to communicate the removal of a documented limitation if it takes more than 30 days to remove or repair the limitation after it is identified. (R3.1 requires the communication within 30 days of the identifying the limitation, but the repair or removal could take longer than 30 days, depending what the causes for the limitation are.)
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected. The note on the graph of Attachment 1 formally states that the No Trip Zone excludes the boundary line.		

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard allows loopholes which undermine reliability. **Part 5.2 gives an allowance for loss of up to 10% of units at a site with many small units, which is analogous to a runback in power on a single larger unit. The SDT does not agree that the exceptions written unduly compromise reliability.** Suggest revising Requirement 5.6 from "may retroactively grant a temporary exemption" to "may grant a retroactive temporary exemption". **The SDT agrees and has made the suggested revision.** The magnitude of voltage excursions at the point of interconnection may be different from the generator terminals where generator relays receive their voltage inputs. **The SDT agrees that the voltage at the point of interconnection to the transmission system will almost always be different than the voltage at the generator terminals. It is not practical to define the generator terminal voltage for an event on the transmission system considering all of the different configurations of generators and transformers. Each Generator Owner will have to evaluate the designs for his particular equipment.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Exelon Corp.	No	It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the "no trip zone." If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. Relays that are known to drift from their settings should either be calibrated more frequently or set such that a tolerance is built into the relay setting so that the drift will not cross the "no trip zone" boundary.		
Texas Reliability Entity	No	While it is technically feasible to set generator protective relays to meet the intent of this Standard, there are technical limitations that may prevent manufacturers from achieving it, especially if the term "generating plant" includes auxiliary equipment within the plant that is required for the generator to continue to operate. The standard needs to clarify if and how the limitations of auxiliary equipment are to be addressed in connection with applicable generating facilities.
Response: Thank you for your comments. NERC standards do not specify how reliability goals are to be accomplished. There are already similar requirements in effect in parts of Europe and Asia. The implementation schedule for Requirement R5 allows six years before the requirement goes into effect in order to allow North American engineers to determine optimal methods for accomplishing the goal.		
ACES Power Marketing Standards Collaborators	No	It is not clear to us why this requirement is needed given the many tariffs that already exist to govern interconnection requests. These tariffs already have well established facility connection requirements. If the requirement persists, we believe it actually belongs in the FAC-001 standard which establishes facility connection requirements for new facilities including generators. While we believe that this requirement is probably technically achievable in most cases, there should be exceptions available. It looks like Part 5.3 will allow the Transmission Planner to offer these exceptions. However, this does not consider that the Transmission Planner in many cases (especially organized markets) is not the entity evaluating interconnection requests. Thus, the Planning Coordinator should be allowed to grant exceptions in those situations as well. **The SDT was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. The SDT does not agree that placing the requirement in an Interconnection Agreement would achieve the desired performance goal.** The need to supply the bases for the estimate in Part 4.2 is not clear, offers no

Organization	Yes or No	Question 7 Comment
		reliability benefit and is administrative in nature. Of the three bases listed, (experience, actual event histories, or sound engineering judgment) what will the RC, PC, TOP, or TP do with the bases? Will they decide the bases are invalid and substitute their own judgment? If so, what is the purpose of getting an estimate from the Generation Owner anyway? It appears to be a documentation requirement that offers no reliability benefit or even information for which the recipient of the information could take action. **The SDT agrees and has removed the wording that required the Generator Owner to supply the basis for the estimate to the requesting entity.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Puget Sound Energy	No	Steam units appear to have very tight frequency requirements, and the damage is cumulative. In order to protect the prime mover, after several under frequency operations the units may need to immediately trip offline.
Response: Thank you for your comments. A number of regions in North America already require operation to underfrequency levels more stringent than those described in this standard. Manufacturers are able to build turbines to meet these requirements. If a particular unit has experienced cumulative damage to the extent it can no longer meet Requirement R5, the Generator Owner may request an exemption from the Reliability Coordinator per Part 5.5. The RC can determine if there is more reliability gain to the grid by having the unit operational with a risk that it may not remain connected during an excursion.		
MRO NSRF	No	A Standard cannot tell us what or how a generator needs to be built. Section 215 of the Federal Powers Act "(i) Savings Provisions, (2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services". We believe that R5 is directing "GO's to design, build and maintain new unit..." and is in violation to the Federal Power Act as stated above. **This requirement does not specify what equipment a generation facility needs to install. It does specify how it is to perform under certain conditions. The requirement does not indicate that a Generator Owner has to build**

Organization	Yes or No	Question 7 Comment
		anything at all, so the cited section of the Federal Power Act does not apply. It is true that a new plant that trips due to an excursion as defined in this standard would be out of compliance (with certain caveats as described in Parts 5.1 – 5.7). Since there are already similar grid requirements in effect in parts of Europe and Asia, the SDT believes it is possible to build a plant to meet Requirement 5 without a need for "future technology." The question was posed to ascertain if anybody is aware of valid technical reasons why it cannot be done with existing technology. There are many factors that a Generator Owner must consider when making a decision to build a new facility. Regulatory compliance may be one factor. As R5 is written, if an entity builds a new unit and it trips for a voltage or excursion event within the parameters of Attachment 1 and 2, the entity is non compliant. **The SDT agrees that this interpretation is correct. However, per Requirement R5, Part 5.5, the Generator Owner could ask the Reliability Coordinator for a retroactive exemption if he determines how to address the limitation that caused the unit to trip.** This Requirement seems to be based on future technology that does not exist today. The SDT should state that the parameters of Attachment 1 and 2 "should" prevent a unit from tripping. R5 is written as an absolute and may reduce a new unit from being built. With the risk of non compliance being $1 million per day, it is easier and less risky not to even build a new unit. **There are already similar requirements in effect in parts of Europe and Asia, so the SDT does not believe meeting the reliability goal will require "future technology." Evaluation of risks and rewards has always been a part of determining when and where to build generating resources.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations	No	It is possible for new facilities to buy steam turbines that permit operation in accordance with Att.1. We cannot confirm that it is possible to do so for all fossil unit sizes or generation unit types, however, and recommend that question 7 above be put to OEMs. This is particularly the case for gas turbine engines, for which the

Organization	Yes or No	Question 7 Comment
		limiting factor may be surge avoidance rather than resonance margins. Note also that such units may auto-unload at abnormal frequencies. This action may not provide the grid ride-out capability wanted, despite satisfying R5's no-trip requirement. The general acceptability stated above for steam turbines bears clarification, however, because OEM guidelines for off-frequency operation typically have a lifetime basis. That is, each transient results in cumulative fatigue damage. The frequency curves of PRC-024-1 are consequently not acceptable for an unstable grid that often swings to the max-specified deviations, and a statement should be added to this standard to the effect that the no-trip zones of Att. 1 apply for frequency excursions to the extremes no more frequently than once per decade. **A number of regions in North America already require operation to underfrequency levels more stringent than those described in this standard. Manufacturers are able to build turbines to meet these requirements. If a particular unit has experienced cumulative damage to the extent it can no longer meet Requirement R5, the Generator Owner may request an exemption from the Reliability Coordinator per Part 5.5. The RC can determine if there is more reliability gain to the grid by having the unit operational with a risk that it may not remain connected during an excursion.** Att. 2 presents a problem in that the deviation location is specified to be the point of interconnection, but GOs are being asked to confirm that all MV and LV devices required to maintain the unit on-line will not drop-out. An excursion to -10% voltage on the 230 kV span would correspond to -10% on the LV and MV systems only for theoretically ideal transformers, and the actual transient at critical loads may be greater. It would not be possible in any event to get OEMs to guarantee that the auxiliary equipment they supply will not drop-out for the Att. 2 excursions of 10 minutes at -10% voltage, 2 sec at -35% or 0.2 sec at -55%. The industry standard on this subject is ANSI C84.1, which stipulates voltage boundaries of +/- 5% for continuous operation and +/- 10% for emergency operation of no specified duration. If NERC feels that the criteria of Att. 2 are important for BES reliability they should start by asking the appropriate ANSI and IEEE committees to revise their standards

Organization	Yes or No	Question 7 Comment
		accordingly. We cannot support PRC-024-1 until its criteria become the nationally-accepted norm, because we otherwise would be making a commitment that it is impossible to fulfill. **The SDT agrees that studies will need to be done to design generating units (especially their auxiliary systems) to be able to ride through the types of transmission system voltage excursions defined in this standard. Since similar requirements are already in effect in parts of Europe and Asia, the SDT believes it is technically feasible. ANSI C84.1 sets standards for steady-state operating voltages and does not apply to voltage transients.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Power	No	Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The "maintain" requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.
Response: Thank you for your comments. The SDT is charged with meeting the reliability recommendations of FERC Order 693 and the 2003 Northeast Blackout Report. Maintenance is required for most equipment to ensure reliable operation. Contactor coils may have to be supplied from a source isolated from transmission system voltage excursions to ensure their reliable operation.		
Progress Energy	No	Progress Energy has a concern associated with the voltage ride through curve referenced in R5 (Attachment 2). The concern is not about setting the relay protection to ride through this transient or the generators capability of riding through

Organization	Yes or No	Question 7 Comment
		such a transient but of the physical capability associated with the large pumps and motors in the auxiliary equipment that would be subjected to this transient. A lot has to do with the size of the motors at the 4160 or 6900 volt level and the control relays at the 480 volt level. After 9 cycles at zero voltage the phase of the motor decay voltage and the incoming line voltage of the large motors may have shifted significantly causing large currents to be drawn when the voltage is restored to the motor. This could cause significant cyclical torques on motor shafts that can damage the shaft over time. Also the control contactors for most 480 volt control circuits do not hold in for less than 60 -70 % voltage. The capability of UPS systems are not sufficient to power the large motors being discussed and it may not be feasible to UPS all the plant 480 volt control circuitry. (We wouldn't be concerned with 480 if we thought we would lose higher voltage equip...) To implement this requirement as presently worded appears to be impractical and could prevent building of any new generating facilities at reasonable cost. **The SDT agrees that shaft torques on large motors is something that needs to be considered in designing the auxiliary system, but that is a concern for existing plants as well unless they have high speed under voltage bus tripping. Presumably, a new facility designed to ride through the voltage excursion described in the standard would include means of mitigating some of the effects of the excursion (e.g. unit-connected auxiliary transformers) which would reduce the shock on motor shafts. The SDT does not believe it would be necessary to carry the 480 V auxiliary loads on a UPS system. It would be sufficient to power the contactor coils with a UPS or from DC to ensure that they don't drop out on an excursion. Similar voltage ride through requirements are already in effect in parts of Europe and Asia so it appears that it is possible to design facilities to achieve the required performance.** There needs to be some ability to deviate for the specific requirements of the voltage curve in Attachment 2 if it can be show that the fault clearing time for the bulk electric system that the unit is connected to is different than the specific voltage requirements of Attachment 2 or there needs to be some more specific wording excluding the auxiliary equipment from the requirements of this voltage curve**. Part**

Organization	Yes or No	Question 7 Comment
		5.3 of Requirement R5 allows the Generator Owner to use the site-specific voltage recovery characteristic provided by the Transmission Planner for that site. Attachment 2 gives engineers and manufacturers the outer bounds of what might have to be met when designing equipment and facilities for multiple locations.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Tennessee Valley Authority GO/GOP	No	There are specific areas within the no-trip zone curves in attachments 1 & 2 that would violate nuclear safety limits, which are controlled by the NRC. Also, the turbines of large steam-turbine units may be exposed to unsafe operating conditions within the no-trip zone of the frequency curve.
Response: Thank you for your comments. Requirement R5 does not apply to existing plants (nuclear or otherwise). Existing plants with documented technical limitations (including nuclear safety considerations) may obtain an exemption from portions of the No Trip Zones defined in the standard through the process described in Requirement R3.		
Arizona Public Service Company	No	Yes, the requirement is technically achievable. However there is a problem with measure and how compliance may enforce it. Generating units trip for many other reasons other than frequency and voltage excursions. The meaure, as written, will require a GO to prove that the unit(s) did not trip due to frequency or voltage excursion which may be impossible to prove. Even if it finds other reasons, it may be hard to prove that frequency and voltage excursion did not contribute to that other reason. Thus, a GO may be non-compliant unless for each unit trip it can clearly prove that the frequency and voltage excursion did not contribute to trip, which may be impossible to prove.
Response: Thank you for your comments. The SDT believes it is general practice for Generator Owners to investigate and determine the cause of all generating unit trips. Recording unit speed (for synchronous units) or system frequency does not seem overly burdensome. Determining local transmission system voltage may require coordination with the Transmission Operator in some cases, but is not unachievable. This requirement would necessitate adding a step to a trip investigation to evaluate this information to determine if there was an excursion at the time of the trip.		

Organization	Yes or No	Question 7 Comment
PacifiCorp	No	While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
Response: Thank you for your comments. The SDT appreciates the support for the reliability goals. We would add that it will require changes in auxiliary system configuration and equipment as well as the turbine and generator manufacturers' inputs to achieve the goal		
Southern Company	No	We recommend R5 be eliminated. New plants should be subjected to the same requirements as existing plants. The design of plant systems, sub-systems, and components are based on industry technical standards (ANSI, IEEE, ASME, etc.). Establishment of new NERC plant performance requirements must be coordinated with the industry through those standard processes. We believe significant R&D will be required to achieve significant new plant design requirements that can be used to revise the industry technical standards and that plant, system, and equipment designers and builders can meet. The scope of systems and components that must be addressed includes, but is not limited to, turbine generators, transformers, feed pump systems/controls, boiler control systems, reactor protection systems, emergency diesel generators, AC motors, pumps, fans, AC motor contactors, auxiliary relays, etc. In addition, significant costs will be incurred by the industry that we believe demand further justification.
Response: Thank you for your comments. The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs. Similar grid requirements are already in effect in parts of Europe and Asia so it appears to the SDT that existing technology exists to meet the requirements of this standard.		

Organization	Yes or No	Question 7 Comment
AECI	No	In my opinion, there needs to a definition of what is considered to be a new plant. Many plants are being built that were actually plants and projects that started 10 years ago. I do not believe that those plants should be included.
Response: Thank you for your comments. The SDT believes that Footnotes 2 and 4 provide a clear definition of "existing" plants and "new" plants. Plants that are already in the design or construction stages are not considered "new" plants.		
American Electric Power	No	AEP believes that the requirement for new units and plants to not trip within the no-trip zone of Attachment 1 is reasonable, and has precedence in existing reliability region guidelines.To not trip within the no-trip zone of the Attachment 2 is another matter. AEP believes Attachment 2 is inappropriate as a requirement on conventional generation for the following reasons:(1) It has not been found necessary to impose such a requirement as Attachment 2 on conventional generation in the past and we question why this should be proposed now. The appearance of such graphs seems to have been in response to the performance of wind farms that tripped off-line by protective relays when minor fault disturbances occurred on the transmission system. Attachment 2 may thus be an appropriate requirement for wind turbine generators and other non-conventional generation. We ask the SDT why such a requirement now needs to be imposed on conventional generation. If this is being done solely for the standard to appear technology neutral, it does not remove the fact that a new, unnecessary, and possibly onerous requirement is being imposed. **The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain.** (2) Application of Attachment 2 to conventional generation is not straightforward because of the need to translate point-of-interconnection voltage to plant or unit internal voltage, particularly in the time period following fault removal (.15 seconds). Conventional synchronous generators have a substantial capability to control the voltage they are subjected to during a system disturbance (unlike most wind farms)

Organization	Yes or No	Question 7 Comment
		and whose critical auxiliary systems are usually (and should be) served from the generator bus (low side of GSU) and are thus shielded to some degree by the GSU impedance from voltage excursions on the transmission system. **The SDT agrees that it will require engineering studies when designing new generating units to determine the effect of the transmission system voltage excursion on the generator terminals and on the various auxiliary bus voltages taking into consideration the configuration of the various transformers. The SDT does not believe this is unachievable.** (3) Back in 2005, FERC Order 661-A contained a requirement for wind farms to ride through point-of-interconnection faults up to 9 cycles as determined by the actual fault clearing time at the interconnection station. The final order was thought to be sufficient to ensure wind farm fault ride-through by intervening parties including NERC and AWEA without the need for a graph along the lines of Attachment 2. Justification for the content of the final order was that all generation would be treated equitably. Why does the SDT now think it necessary to impose Attachment 2 on new generation? It would seem that deference to TPL standards for the types of transmission system disturbances where stability should be maintained should continue to be an acceptable ride-through criterion for all types of generation. Reference to Attachment 2 in R5 should thus be replaced by a requirement for all generation to ride through normally cleared 3-phase or unbalanced faults at the POI not to exceed 9 cycles. **If the Transmission Planner for a new generation facility can provide the voltage profile for that specific site, then per Part 5.2 the Generator Owner can design his new facility to ride through that profile even if it is less stringent (i.e. uses faster clearing and faster voltage recovery) than Attachment 2. The voltage envelope described in Attachment 2 provides equipment OEM's with an outer boundary on the voltage stress they have to design for.** (4) We do not know the incremental cost to comply with Attachment 2 under R5; however, we believe that it could be very costly to design and build synchronous generating units that would, with a high degree of confidence, remain on-line for any and all disturbances whose POI voltage falls within the no-trip zone. Attachment 2

Organization	Yes or No	Question 7 Comment
		would also be a new requirement without historical precedent and the SDT has not stated how reliability would be improved. With uncertain reliability benefits and uncertain and potentially high incremental costs to comply, we do not think the SDT is in a position to impose this requirement.For these reasons, we believe that reference to Attachment 2 in R5 should be removed. **There are similar voltage ride through requirements already in effect in parts of Europe and Asia. The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT agrees that generating units designed and built to meet Requirement R5 will be more costly than those that cannot meet this reliability goal. The SDT is not in a position to place a monetary value on the consequent reliability gain. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Energy	No	Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The "maintain" requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.
Response: Thank you for your comments. The SDT is charged with meeting the reliability recommendations of FERC Order 693 and the 2003 Northeast Blackout Report. Maintenance is required for most equipment to ensure reliable operation. Contactor coils may have to be supplied from a source isolated from transmission system voltage excursions to ensure their reliable		

Organization	Yes or No	Question 7 Comment
operation.		
Duke Energy	No	The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second is to utilize expensive voltage regulation devices, normally not utilized at power generation plants. This standard shouldn’t dictate a solution to the situation where a generator goes offline due to low voltage on the transmission system, because in many cases the generator going offline may not be a problem for the overall transmission system. In situations where it is a problem, a collaborative effort between the Transmission Planner and the Generator Owner would be the best approach (see AREVA white paper that has been provided to the SDT).An R&D effort

Organization	Yes or No	Question 7 Comment
		should be considered to investigate steam plant ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The voltage profile described in Attachment 2 is specified at the transmission system. This cannot be directly applied to the auxiliary system buses unless the Generator Owner insists on using substation-connected auxiliary transformers. Operating the auxiliaries from unit-connected transformers would provide a much better voltage profile to the equipment. As noted, ANSI C84.1 applies to steady state voltages. This standard does not state that any transient condition lasting longer than one second is defined as steady state. In IEEE 1159 a long duration variation is defined as being longer than one minute. The SDT is charged with implementing recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs. Similar grid requirements are already in effect in parts of Europe and Asia so it appears to the SDT that existing technology exists to meet the requirements of this standard.		
Ameren	No	(1) We understand this to include generating plant auxiliary load based on the GVSDT reply to our draft 2 comments. If still is the case, please clarify and explicitly insert “including its auxiliary systems” after generating plant so that all GO understand it. **The SDT agrees and has added “(including auxiliary systems)” to the wording in the requirement.** (2) Many 480V class contactors drop out in the 70% to 80% voltage range, so we doubt they’ll ride through the 2 to 3 second portion of the voltage excursion. The middle portion of your voltage excursion curve is more stringent than the CBEMA and SEMI curves, both of which recover to 80% in 0.5 sec. Transmission system protection in our system will clear faults faster than the proposed voltage excursion curve, thus in effect yielding a voltage recovery curve with shorter durations for the voltages specified. We would ask the GVSDT to consider what we feel is a more realistic approach of designing a new generating facility to the Transmission Planner’s voltage recovery characteristic allowed for in R2 part 2.1.1 is achievable now. What was the basis on which the proposed voltage excursion curve developed? **The curves cited in your comments specify voltages at the equipment. The voltages specified in Attachment 2 of the standard are at the high side of the generator step-**

Organization	Yes or No	Question 7 Comment
		up transformer. A new generation facility would have to be designed such that contactor coils and delicate electronic equipment are isolated from the full extent of a transmission system voltage excursion. If the Transmission Planner for a new generation facility can provide the voltage profile for that specific site, then per Part 5.3 the Generator Owner can design his new facility to ride through that profile even if it is less stringent (i.e. uses faster clearing and faster voltage recovery) than Attachment 2. The voltage envelope described in Attachment 2 was developed from studies in WECC and SERC of multiple fault scenarios and their recovery characteristics. It is similar to the envelope described in FERC Order 661-A that wind units already are required to meet and to grid requirements already in effect in parts of Europe and Asia.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Southern California Edison Company	No	The language in the requirement is acceptable, but the frequency curve identified for generators is too restrictive for hydro facilities, which are often dispatched to provide VAR and voltage support. SCE's hydro generation plants operate at very low RPM, which provides them with the ability to operate safely above (60-78 Hz) and below (<58 Hz) the frequency curves in Attachment 1 and Attachment 2, respectively. As a transmission operator, SCE applies this flexibility in its hydro generation plants to compensate for system instabilities resulting from VAR and voltage excursions. In addition, SCE's employs its hydro plants to support system restoration.
Response: Thank you for your comments. The SDT is not clear on your response. It appears that you want hydro units to be able to operate below 57.0 Hz and/or above 61.7 Hz that are the boundaries for the WECC interconnection. The standard does not require that any generators trip if the frequency goes outside of the No Trip Zone defined in Attachment 1, it only prevents tripping within the No Trip Zone.		
Cowltiz PUD	No	Cowlitz supports Clark County PUD's position. Please verify the following: The problem is that PRC-024 skips a frequency step in the low frequency operating area. The generator frequency ride through of Attachment 1 is inconsistent with the

Organization	Yes or No	Question 7 Comment
		current WECC Off Nominal Frequency plan and the frequency ride through in the proposed WECC-0065 regional criteria. The PRC-024 ride through could cause a combustion turbine to operate at 58 Hz for a duration that would cause damage to the turbine blades. The current WECC ONF ride through avoids this.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Indiana Municipal Power Agency	No	Is the technology to meet this requirement even currently available to a newly built generating facility? To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the gird on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available? IMPA believes that this standard will be reviewed by NERC in five years or sooner and at the time the SDT can revisit this possible requirement to see if the technology to keep a generating facility on line during a voltage or frequency excursion has been proven. Or a condition could be added that says new units shall be designed and built with the frequency and voltage excursion equipment if it is the industry standard, readily and commercially available and comes at competitive market prices.
Response: Thank you for your comments. The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs. Similar grid requirements are already in effect in parts of Europe and Asia so it appears to the SDT that existing technology exists to meet the requirements of this standard.		
Pepco Holdings Inc. & Affiliates	Yes	Yes, it is possible to design a new facility to operate within the requirements identified in this standard. However, it may require specification of equipment with higher than normal overvoltage capabilities. Also, significant analyses would have to be conducted on the behavior of plant control systems (exciter controls, boiler

Organization	Yes or No	Question 7 Comment
		controls, etc.), as well as equipment connected to auxiliary busses (including low voltage motor contactors) to ensure that all systems are designed with appropriate ride-through capabilities.
Response: Thank you for your comments. The SDT agrees with your position.		
ISO New England Inc	Yes	The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard appears to allow loopholes which undermine reliability.
Response: Thank you for your comments. Part 5.2 (now 5.1) gives an allowance for loss of up to 10% of units at a site with many small units which is analogous to a runback in power on a single larger unit. The SDT does not believe the exceptions written in Requirement R5 unduly compromise reliability.		
Xcel Energy	Yes	We believe the requirement is technically achievable, but question whether the additional cost to design and build plants to meet this goal is the most effective way to spend money to increase grid reliability.
Response: Thank you for your comments.		
Ingleside Cogeneration LP	Yes	In our view, the time frame allotted to accommodate PRC-024-1's frequency and voltage ride-through specifications for new generating facilities is reasonable.
Response: Thank you for your comments.		
GenOn Energy	Yes	Conditionally yes; unconditionally no. It is achievable for any plant with a modern AVR and unit connected auxiliaries. Problems arises for unique circumstances that may require auxiliaries that are not unit connected (directly connected to transmission systems). Existing plants orginally designed with unit connected

Organization	Yes or No	Question 7 Comment
		auxiliaries have been forced to extend auxilary power feeds directly from transmission level voltages.It is believed that transmission system performance better than Attachment 2 is available at the majority of locations, and therefore, it is not necessarily appropriate to make this the design criteria for every future generating station.
Response: Thank you for your comments. Requirement R5 does not apply to existing plants. Part 5.3 of Requirement R5 allows the Generator Owner to design to a less stringent voltage profile (e.g. a profile with faster clearing and faster recovery) if the Transmission Planner can provide the profile for the specific site in question. Attachment 2 provides the outer bounds that may be used by engineers and manufacturers to determine the limits of what they may be required to withstand.		
American Wind Energy Association	Yes	Yes, the feedback we have received from wind turbine manufacturers is that, if such a standard were not applied retroactively and were implemented with a grace period extending at least several years into the future, wind plants would be able to meet these requirements.
Response: Thank you for your comments. The implementation for Requirement R5 is set at six years past approval of the standard. Requirement R5 applies only to "new" plants (as defined in Footnotes 2 and 4) and does not apply retroactively to existing plants.		
Southwest Power Pool Standards Development Team	Yes	
Dominion	Yes	
Imperial Irrigation District (IID)	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td>American Transmission Company, LLC</td><td>Yes</td><td></td></tr>
<tr><td>Essential Power, LLC</td><td>Yes</td><td></td></tr>
<tr><td>FirstEnergy Corp</td><td>Yes</td><td></td></tr>
<tr><td>PSEG</td><td></td><td>We do not know whether new units installed 6+ years out can meet the requirements. We suggest that the team should reach out to OEMs for their input.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. One OEM has been participating on the SDT, and the SDT has inquired to other OEM's. In addition, similar grid requirements are already in effect in parts of Europe and Asia. The SDT believes new technology is not required to meet the requirement, but posed the question to determine if industry knew of specific reasons why it cannot be implemented.</td></tr>
<tr><td>Consolidated Edison Co. of NY, Inc.</td><td></td><td>Requirement 5.6 suggested wording revieion:Replace "may retroactively grant a temporary exemption" with "may grant a reactoactive temporary exemption"</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT agrees and has made the suggested revision.</td></tr>
<tr><td>Independent Electricity System Operator</td><td></td><td>We believe this requirement is achievable for most cases. However, provision should be given to the Generator Owners which for specific technical reasons are unable to design a generating unit to comply with the requirements. As worded, R5 does not contain this provision. We therefore suggest that R5 be appended with ", or provide the technical reasons why this is not achieveable" after "the following conditions and exceptions".</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT is not aware of technical limitations that would prevent the design and construction of a new generation facility to meet Requirement R5. There are already similar grid requirements in effect in parts of Europe and Asia.</td></tr>
</table>

Organization	Yes or No	Question 7 Comment
Georgia Transmission Corporation		Don't know
Los Angeles Department of Water and Power		LADWP does not have comments on this question at this time.

8. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-024-1?

Summary Consideration: The Effective Date section was modified for Requirements R1, R2, R3, R4, and R6 to reflect a five-year implementation at the request of several stakeholders. The wording in Requirement R1 was revised for clarity, Part 1.1 (rate of change of frequency) was removed and new Parts 1.2 and 1.3 were added for consistency with Requirement R2 at the request of several stakeholders. Minor changes in the wording in Requirement R2 were made to improve clarity at the request of several stakeholders. The structure of Requirement R4 was modified and minor wording changes were made to improve clarity at the request of several stakeholders, though no changes were made to the intent of the requirement. Part 5.1 and Subpart 5.1.1 were incorporated into the body of Requirement R5 so that the remaining Parts of this requirement describe exceptions (i.e. allowances to trip). Minor wording changes were made at the request of multiple stakeholders to clarify wording in Parts 5.1 – 5.6 of Requirement R5. The allowable time to respond to a request for generator protection settings in Requirement R6 was increased from 30 days to 60 days at the request of several stakeholders. The Violation Risk Factors for Requirements R1, R2, and R5 were changed from High to Medium at the request of several stakeholders. Minor wording changes were made to Measures M3, M4, and M5 were made for clarity at the request of several stakeholders. The time frame referenced in Measure M6 was modified to correlate with the change made in Requirement R6. The wording in the Data Retention section was revised at the request of one stakeholder and now reflects the wording used in other recently-approved standards. Minor changes were made in the VSL's for Requirements R1, R2, R3, and R4 to add clarity or correct errors mentioned by several stakeholders. The wording in the Severe VSL for Requirement R5 was revised to add a reference to Parts 5.1 – 5.6 and the tardiness levels in the Requirement R6 VSL's were revised to reflect the change in the requirement. The underfrequency curve for the Western Interconnection and corresponding data table were corrected in Attachment 1 at the request of many stakeholders in the WECC region. Curves for the ERCOT Interconnection and a corresponding data table were added to Attachment 1 at the request of ERCOT. The term "base voltage" was replaced with "nominal operating voltage" in Clarification #1 to Attachment 2 at the request of several stakeholders. Minor wording changes were also made to Clarifications #2, and #5 to better convey the intent of the SDT in response to questions presented by several stakeholders.

Organization	Yes or No	Question 8 Comment
Southern Company		Yes: 1) We respectfully disagree with the SDT's response to our prior comment related to maintaining the safety of the reactor core at nuclear plants for voltage or frequency transients. The intent of our comments is to ensure that application of this standard to nuclear units is coordinated per the requirements of NUC-001.

Organization	Yes or No	Question 8 Comment
		Employing any changes to the grid frequency and voltage ride-through requirements may impact the licensing and design basis of nuclear facilities. NUC-001-1 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown. This is achieved through development of Nuclear Plant Interface Requirements (NPIRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements (NPLRs) and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities. The NPLRs are requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance or transient condition is important. It is essential that this process be followed closely in attempting to apply any new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant's licensing and design basis. The safety of nuclear power plants is of paramount importance. **The SDT respectfully disagrees that this standard is in conflict with the requirements of NUC-001. Requirement R4.3 of NUC-001 acknowledges that it is not always possible to operate the transmission system to meet the requirements of a particular site's NPIR. The Reliability Coordinator is an applicable entity to the NUC-001 standard, and as such can be involved in granting an exemption (per PRC-024 part 5.6) to any new nuclear facility that cannot meet the ride-through requirements of Requirement R5 because of a conflict with the facility's NPIR if the Reliability Coordinator agrees there is a reliability benefit to allowing the facility to operate with a greater risk of tripping during a frequency or voltage excursion. Existing nuclear facilities can get an exemption from portions of the no trip zones defined in Attachments 1 and 2 through the process defined in Requirement R3 based on the regulatory nuclear safety requirements.** 2) R1, R2, and R3 state "each" non-protection system equipment limitation. This

Organization	Yes or No	Question 8 Comment
		should be clarified to state "each non-protection system equipment limitation associated with the applicable protection function." **The SDT agrees and has removed the term "non-protection system equipment limitation" from Requirements R1, R2, and R3.** 3) Event monitoring equipment required by M5 will be a significant burden on GOs to only prove a negative. We believe M5 should be removed from the standard, because the benefits gained do not justify the costs. **The SDT does not agree that event monitoring equipment poses a significant burden compared to the cost of a new generating unit.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Ameren		(1)Under Applicability it should state that 'all existing generators meeting registry criteria' and also 'new generating units that will meet the registry criteria.' **The SDT feels that the applicable generators owned by a "Generator Owner" is clearly stated in the Registry Criteria and that no further clarification is required.** (2)Please modify the Effective Date and Implementation Plan to provide a five year phase-in to match that of the companion PRC-019-1. Generator voltage protective relaying must be reviewed in both these standards, and we believe that doing so on the same schedule will yield a better coordinated result and less confusion. Each of these standards will consume valuable resource time and the efficiency of reviewing each generator concurrently will improve BES reliability **The SDT agrees and has changed the implementation period, relative to Requirements R1, R2, R3, R4 and R6, of PRC-024-1 to match that of PRC-019.** (3)Please add 'R1, 1.3 If clearing a system fault necessitates disconnecting a generator, then this action is acceptable within the "no trip zone".' This affords the same practical reality recognized for voltage excursions. **The SDT agrees so that there is consistency between Requirements R1 and R2. Part 1.2 has been added in the current revision.**

Organization	Yes or No	Question 8 Comment
		(4)Please be clearer regarding the Voltage Ride-Through curve. Attachment 2 Voltage Ride-Through Curve Clarification #2 could be interpreted to imply that the curve is based on three phase faults. But the inclusion of #5 states that phase-to-ground or phase-to-phase voltages (minimum or maximum as appropriate) are assumed. Of course, for a three phase fault the each phase's voltage is equal. So we interpret #5 to mean that the actual fault type to be simulated should match the Transmission Planning criteria, which for example may be double or single line to ground faults with delayed clearing. We recommend to the GVSDT to align this with the TPL standards, which use three phase fault or single line to ground fault with Normal Clearing, but only single line to ground fault with Delayed Clearing. We would appreciate an example or in depth explanation to tie these together. Please annotate Attachment 2 with references to R2 and clarifications on page 18. **Clarification #2 to Attachment 2 has been modified with an added statement saying "The curves apply to voltage excursions regardless of the type of initiating event." The SDT believes it is not realistic to design generating units to be able to withstand zero voltage at the point of interconnection to the transmission system for extended time periods. None of the other grid standards for generator ride through that the SDT reviewed contain requirements to ride through delayed clearing.** (5)Delete 'or generating plant' from R1, R2, and R3 to be clear that the generating plant auxiliary loads are not subject to these requirements. Alternatively, restate R3 as "...that prevents a generator frequency or voltage protective relay generating unit or generating plant, from meeting the criteria in Requirements R1 or R2 including study results, experience from an actual event, or manufacturer's advisory" to be consistent with R1 and R2. **The SDT agrees and has removed the words "or generating plant" from the Requirements. The wording of R1 and R2 has been changed to indicate that the relaying included in the scope of R1, R2, and R3 are generator voltage relays and generator frequency relays, both of which trip the unit when they operate**. (6)At the end of Requirement R4.2, please add "the Transmission Planner's voltage recovery characteristic from R2 part 2.1.1" since that may well have bearing on the estimate. **Since it is not a requirement for the Transmission Planner to provide the**

Organization	Yes or No	Question 8 Comment
		voltage profile defined in Part 2.1.1. (now Part 2.2), the SDT does not believe it can be required to provide this information in Requirement R4. (7)From our perspective, Requirement R5 doesn't make sense for a newly designed generator. We would suggest the GVSDT to realign M5 to be prospective and to require the GO to provide design basis evidence appropriate for the stage of design of new generators. In early conception stages, the GO would request the Transmission Planner's frequency and voltage excursions. Then the GO would design the generator train and auxiliary system to ride through, and if infeasible, request technical exceptions. Late in the design process the generator frequency and voltage protective trip settings would be determined; it would be appropriate at that time to provide them R6 requests for future system studies. **The SDT appreciates this suggestion, but in discussions with the US regulatory agency regarding this approach, they indicated it could only be used in addition to the performance requirement, not in lieu of performance. The SDT does not believe it would increase grid reliability to require Generator Owners to do both.** (8)For Requirement R6 we oppose providing this specific information to all these functional entities, given that they are getting the R4 estimate of performance during such excursions. **The information would only be given to the entity that requested the information. The number of entities who are allowed to request the information is restricted to those named in Requirement R6. The performance estimate requested in Requirement R4 is different in that it must consider the performance of the entire generating unit including auxiliaries, not just the protection system.** (9)If R6 is retained, please make the following changes: (a) We strongly prefer a reporting of exceptions to the standards frequency and voltage excursion ride-through curves rather than reporting all these relay settings. Use PRC-006-1 Attachment 1 page 28 of that standard for frequency reporting. Develop a similar envelope for voltage reporting. If a Transmission Planner's voltage recovery characteristic allowed for in R2 part 2.1.1 differs that should be provided for the

Organization	Yes or No	Question 8 Comment
		generators in their area. Generator Owners would then report exceptions. (b)Insert "frequency and voltage" between generator and protection in the first line.(c)Delete "and within 30 calendar days of any change to those trip settings," because this creates an open ended obligation on the GO. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested would need to be reported. The SDT has added the words "…unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).** (10)We would suggest the GVSDT to not capitalize frequency and voltage excursions as they are no longer defined terms. **The SDT agrees and has made the suggested changes.** (11)We suggest the GVSDT to replace the time-based or binary VSL for R1, R2, R3, R4 and R6 with a VSL in terms of the GO % of MWh produced for the time period of violation. This better characterizes the risk to BES reliability. We propose <5% for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe. As presently proposed a generator with no operating hours could cause a GO to incur a Severe violation though it posed no risk to the BES. **The SDT discussed this approach with NERC earlier in the drafting process and was told it is not an acceptable method of structuring a VSL.** (12)From our perspective, the VSL for R5 doesn't make sense for a newly designed generator. We suggest, a time-based VSL with x days late in providing R4 or R6 type information. . In this regard, we propose to the GVSDT 30 days late for Lower, 31 to 60 days late for Moderate, 61 to 90 days late for High, and >90 days for Severe. **The**

Organization	Yes or No	Question 8 Comment
		SDT does not see how a tardiness structure would apply to a performance requirement. (13)PRC-024-1, R2.1 states that generator terminal voltage refers to Attachment 2. However, in R2 itself, footnote 3 states that voltage excursion applies to point of interconnection, meaning the GSU high-side. We suggest the SDT resolve this discrepancy. **Requirement R2, part 2.1 states that Attachment 2 applies to conditions on the transmission system when the generator is operating within 95% to 105% of its rated voltage. The SDT does not see a discrepancy.** (14)Attachment 2 should include footnote similar to footnote 3 provided for R2. **The SDT does not believe it is necessary to insert duplicate footnotes.**
Response: Thank you for your comments. Please see the responses to individual comments above.		
Pepco Holdings Inc. & Affiliates		1) If it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with close in three phase faults, then it is equally as important to have them remain on-line for single line to ground faults, which are much more common. During a phase to ground fault at the point of interconnection the faulted phase voltage collapses to zero but the unfaulted RMS phase to ground voltages could rise as high as 80% of the RMS line to line voltage for an effectively grounded system (with a coefficient of grounding = 80%). This is well in excess of the 1.2 p.u. overvoltage requirement presently shown in Attachment 2. As such, for the unit to ride through phase to ground faults at the point of interconnection then the short time 1.2 p.u. overvoltage threshold at the point of interconnection needs to be raised above 0.8 x 1.73 = 1.38 p.u.. In summary, the overvoltage portion of the curve in Attachment 2 should be modified to require the unit to stay connected with a 138% phase to ground overvoltage appearing at the point of interconnection for up to the expected clearing time of a Zone 1 phase to ground fault. **The SDT agrees that the phase to ground voltage can rise to the level noted in your comment during single phase to ground faults. The SDT has modified Clarification #5 to remove the words "…phase to ground…" If only the phase-to-phase voltages are evaluated,**

Organization	Yes or No	Question 8 Comment
		then the limit can remain at 1.2 p.u. voltage. 2) The standard should make clear whether the no-trip zone shown in Attachments 1 and 2 includes the boundary curves themselves. **There is a text box in the middle of the graph that specifically states that the no trip zone does not include the lines. The SDT does not believe any further explanation is necessary.** 3) To add clarity and avoid confusion, the ordinate of the graph in Attachment 2 should be labeled Per-unit RMS Voltage Measured at the Point of Interconnection. **Clarification #5 to Attachment 2 has been modified to include the term "RMS."** 4) The current language in Item #1 of the "Voltage Ride-Through Curve Clarifications," which appears on the last page of the standard, may cause problems for generator interconnections on the 500kV system. Most transmission Planners use "nominal" transmission system voltage levels as the "base voltage" in their system models. These are the same "nominal" system voltages specified in ANSI C84.1. In most cases, C84.1 shows the maximum allowable system voltage as 105% of nominal, with the exception of 500kV. For 500kV systems the maximum system voltage is 550kV, and it is routine to operate the transmission system above 525kV (105% of nominal). If the "base voltage" at the point of interconnection used in planning studies is 500kV but the system is normally operated above 105%, then the generation protective systems must be capable of maintaining operation with the continuous voltage at the point of interconnection above 105% of "nominal" (at least for 500kV systems). This being the case the voltage base in Attachment 2 for 500kV systems will by necessity have to be something other the "nominal base voltage" used by the Transmission Planner in their system models. Perhaps this could be addressed by re-wording Item #1 to read "1. The per unit voltage base for these curves is to be specified by the Transmission Planner at the point of interconnection to the Bulk Electric System (BES)." By removing the reference to "the base voltage used in the system models by the Transmission Planner" it eliminates the conflict mentioned above. On the other hand it now requires the Transmission Planner to provide this "other than nominal base voltage for 500kV systems" to the Generator Owners. **Since some 500**

Organization	Yes or No	Question 8 Comment
		kV systems may not operate in the same manner as yours, the SDT would prefer not to specify different ranges for particular voltage classes. In order to address your concern, the SDT has modified Clarification #1 to Attachment 2 by removing the words "base voltage" and "in the system models" and has replaced them with "nominal operating voltage specified by the Transmission Planner." The SDT believes this will address the different operating criteria used in different regions. 5) The word "crest" should be removed from Item #5 of the "Voltage Ride-Through Curve Clarifications," which appears on the last page of the standard . The voltages referred to in this standard are all per-unit "RMS" voltages, not "peak" or "crest" voltages. **The word "crest" is necessary for equipment manufacturers to know what the limits are that they must meet in designing equipment to meet the requirements of this standard. Under normal operating conditions per unit crest and per unit RMS are the same, but during high voltage excursions, magnetic saturation creates differences.** 6) Typically unit connected generator protection packages, which include frequency and voltage protective elements, are supplied by voltage transformers connected on the terminals of the generator rather than on the high side of the generator step-up (GSU) transformer. For frequency elements, the frequency at the terminals of the generator is the same as on the high side of the GSU transformer. So comparison of frequency protective element set points can be made directly with Attachment 1. However, this is not true for voltage. The generator terminal voltage could be higher, or lower, than the system voltage on the high side of the GSU transformer depending on the voltage drop across the transformer, which varies depending on the generator real power output and whether the generator is supplying or absorbing reactive power. Since this standard requires the generation to remain connected for specific voltage criteria as measured at the point of interconnection, but the voltage sensing protection is connected to the generator terminals, some technical guidance (with specific examples) must be provided to allow the Generator Owner to properly translate these voltage criteria to the voltages seen by the protective relays on the terminals of the generator. Otherwise an incorrect evaluation may result. It is

Organization	Yes or No	Question 8 Comment
		recommended that a Technical Reference Document similar to the "Power Plant and Transmission System Protection Coordination" document developed by the NERC System Protection and Control Subcommittee be produced, or the above mentioned document revised, to provide illustrative examples of how to apply the Attachment 2 POI voltage criteria to voltage sensing protective elements connected to the terminals of the generator. **There are text books that cover the necessary calculations. Clarification #6 to Attachment 2 provides guidance to the conditions to be used when doing the evaluation.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Texas Reliability Entity		1) Purpose Statement: If we correctly understand the intent, the second comma should be removed. **The SDT agrees and has removed the comma.** 2) Does the SDT want to consider any specific requirements regarding generators that are connected as synchronous condensers, and is it the intent of the standard to cover this operating mode? **The SDT considered including synchronous condensers as applicable facilities for this standard. The SDT determined that it is not necessary to include synchronous condensers because frequency transients within the scope of this standard are not a serious concern for synchronous condensers, and most synchronous condensers do not have the auxiliary systems that would cause a condenser to trip under the voltage transients defined in this standard.** 3) All requirements: Need to clarify the phrase "generating unit or generating plant". Does the "generating plant" phrase imply that the frequency and voltage setting criteria also applies to plant auxiliary equipment (referenced in R4)? In ERCOT, we have seen multiple instances where close-in faults have created low voltage conditions which caused auxiliary equipment to trip (boiler feed pumps, baghouse fans, etc.) which in turn caused a unit runback and trip. If the intent of this standard is to also cover plant auxiliary equipment, then this needs to be very clearly stated in the Applicability section and/or in the Requirements. **The SDT agrees and has removed the words "or generating plant" from the Requirements. The wording of**

Organization	Yes or No	Question 8 Comment
		R1 and R2 has been changed to indicate that the relaying included in the scope of R1, R2, and R3 are generator voltage relays and generator frequency relays, both of which trip the unit when they operate. 4) R1 and R2: The SDT may want to consider adding Volts per Hertz criteria. For example: ERCOT region criteria currently states a generator must remain connected if Volts/Hertz is less than 105% of generator design voltage and frequency, and also if Volts/Hertz is less than 116% of generator design voltage and frequency for less than 1.5 seconds. **The V/Hz relaying applicability is addressed in Footnote 1. R1 and R2 apply to situations where a unit is tripped by generator frequency relaying or voltage relaying.** 5) R1: Need to add "or generating plant" to end of R1. **The SDT has removed the words "or generating plant" from Requirements R1 and R2 at the suggestion of other commenters, so it is no longer necessary to add it to the end of Requirement R1 for consistency.** 6) R2: Need to specify that the undervoltage "no trip zone" applies to both single-phase and three-phase voltage excursions. **Clarification #2 to Attachment 2 has been modified with an added statement saying, "The curves apply to voltage excursions regardless of the type of initiating event."** 7) R2.1.2 and 2.1.3 need to include the phrase "generating unit or generating plant" versus "generator" to be inclusive of a plant site and provide consistency throughout Standard. **The SDT agrees. The standard has been revised to use the words "generating unit."** 8) R1 and R2 Exclusions: The SDT may want to consider these additional exclusions: a. A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system.b. A generation unit may trip by frequency or voltage protection if the unit is being operated below its Low Sustained Limit (LSL), where LSL is defined as the limit established by the Generator Operator that describes the minimum sustained energy

Organization	Yes or No	Question 8 Comment
		production capability of the generator.c. A generator unit may trip by frequency or voltage protection if the unit is being operated in a "Test" status and is not under AGC control. **The SDT disagrees that these exclusions are needed in Requirements R1 and R2. These two requirements specify how generator protection is to be set, which does not change for different operating conditions. There are similar exceptions written into Requirement R5, which is a performance requirement, to cover these situations for plants designed and built after the standard is approved and this requirement is implemented.** 9) R3: Generator Operators should be required to document "known" equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation. Also need to clearly state if this requirement (i.e. due to the phrase "generating plant") also applies to plant auxiliary equipment, which would require the GO to provide extensive review and documentation on all of their plant auxiliary systems as well. **The SDT agrees and has added the word "known" to Requirement R3.** 10) R5: Need to clearly state if this requirement applies to plant auxiliary equipment. **The SDT agrees and has added "(including auxiliary systems)" to Requirement R5.** 11) In 5.2, insert "nameplate" after "aggregate" to be consistent with R5.1.1. **The SDT agrees and has added the word "nameplate," as suggested.** 12) R5 Exceptions: The SDT may want to consider these additional exceptions: (a) A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system. (b) A generator unit may trip by frequency or voltage protection if the unit is being operated in a "Test" status and is not under AGC control. **The SDT believes that the first suggested exception is already covered under part 5.1 (now part of the main body of the requirement). The SDT is not sure why AGC status is of issue since many base loaded units do not run on AGC, but if it would cause certain units to become unstable during an excursion such that it was about to lose synchronism,**

Organization	Yes or No	Question 8 Comment
		then part 5.6 would apply. 13) In Measures M1 and M2: See comment 3 above regarding the use of the phrase “generating plant”. Is it the intent of these measures to also cover frequency and voltage setting sheets for plant auxiliary equipment protection systems? **No. Requirement R1 specifically says, “generator frequency protective relaying” and Requirement R2 specifically says, “generator voltage protective relaying.” The auxiliary equipment protection systems are not in the scope of these requirements.** 14) In Requirement R4, Measures M4 and M5, and some VSLs: Remove capitalization of “Frequency/Voltage Excursions” and similar terms (e.g. Frequency Excursion), which are not formally defined in this standard nor in the NERC glossary. **The capitalization has been removed as suggested.** 15) VSLs for R1, R2, and R3: What is the SDT’s intent regarding a GO that has set its relays per R1 and R2, and has no documented equipment limitations per R3, but still experiences a unit trip within the one of the “no trip” zones in Attachment 1? Is that intended to be a violation of this standard? There is not a VSL for this situation. The VSL for R5 contemplates a violation for tripping in the no-trip zone, but it only covers “new” generation units, and there is not a similar VSL for existing units. **For existing generating units, a trip during a frequency or voltage excursion for reasons other than operation of the generator protection is *not* a violation. For that reason, it is not covered in the VSL’s. Requirement R5 is only applicable to “new” units (as defined in the standard). The standard does not contain an equivalent performance requirement for “existing” units, hence there is no such VSL.** 16) VSL for R1 and R2: The term “technical” should be replaced with “equipment” to be consistent with the Requirements. Need to replace “generator” with “generating unit or generating plant” to be consistent with the Requirements. **The SDT agrees that the word “technical” should be replaced with “equipment” and has made the suggested revision. The word “generator” has been replaced with “generating unit” since that wording is now used in Requirements R1 and R2.**

Organization	Yes or No	Question 8 Comment
		17) VSL for R2: Language should be similar to VSL for R1 with respect to "activated to trip" phrase and to be consistent with the Requirement itself. Suggest replacing "conditions" with "criteria" to be consistent with VSL for R1. **The SDT agrees and has changed the wording in the VSL for Requirement R2 as suggested.** 18) VSL for R3 and R4: What VSL applies if the communication occurs on day 61? It looks like the answer is "none." **The SDT agrees and has revised the number used in the Severe level of the VSL accordingly.** 19) VSL for R3: See comment 9 regarding requirement R3 above. The requirement and VSL should only apply to "known" equipment limitations. **The SDT agrees and has added the word "known" to the VSL.** 20) VSL for R4: Consider changing "unit's performance" to "unit's or plant's performance." **The wording in Requirement R4 refers to "generating unit" so the SDT did not change the wording in the associated VSL.** 21) VSL for R6: Remove the phrase "or limitations," because R3 discusses limitations and the reporting thereof and it is out of place here. **The SDT agrees and has removed the words "or limitations" from the VSL** 22) Attachment 1- Change "Texas Interconnection" to "ERCOT Interconnection". **The labels on Attachment 1 and the associated data tables have been changed as suggested.** 23) Regarding the Voltage Ride-Through Curve Clarifications: The reference to a generation facility's "point of interconnection to the Bulk Electric System" is incorrect, because the generation facility is itself part of the BES. We assume this is intended to refer to the point of interconnection between the generation facility and the transmission facility, and the text should be modified accordingly. **The SDT appreciates your position, but declines to change the wording because other commenters have expressed concern when the term Bulk Electric System is not used.**

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PacifiCorp	Negative	1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." **It appears to the SDT that this comment refers to MOD-026, not PRC-024. Please see the response provided to this same comment in Question 5.** 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **It appears to the SDT that this comment refers to MOD-026, not PRC-024. Please see the response provided to this same comment in Question 5.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by

Organization	Yes or No	Question 8 Comment
		Requirement sub-parts 2.1.1 through 2.1.6." **It appears to the SDT that this comment refers to MOD-026, not PRC-024. Please see the response provided to this same comment in Question 5.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Power		1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the "no trip zone" of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become "Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds." For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. **The SDT feels that the list of relaying included in Footnote 1 needs to be considered in the scope of this standard, as they will be just as effective as voltage only and frequency only relays in tripping the unit during frequency or voltage excursions described by Attachments 1 and 2. V/Hz characteristics from applicable IEEE standards were considered. Clarification #4 to Attachment 2 states: "The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal."** 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; " ... unless the generator owner has identified an equipment limitation ..." **The SDT agrees that Requirement R3 is basically administrative, but ensures the limitations (and associated changes in**

Organization	Yes or No	Question 8 Comment
		protection settings that affect the performance of a generating unit during a frequency or voltage excursion) are communicated to the appropriate planning and operating entities so that its performance can be correctly modeled. 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. **The SDT agrees that an increase in the amount of time allowed for response is warranted. The SDT has changed the time period from 30 days to 60 days.** 4. Overall, this standard should address voltage and frequency relay settings only. **The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report which requires that the standard address performance.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Luminant Energy		1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the “no trip zone” of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become “Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds.” For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. **The SDT feels that the list of relaying included in Footnote 1 needs to be considered in the scope of this standard as they will be just as effective as voltage only and frequency only relays in tripping the unit during frequency or voltage excursions described by Attachments 1 and 2. V/Hz characteristics from applicable IEEE**

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		standards were considered. Clarification #4 to Attachment 2 states: "The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal." 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; " ... unless the generator owner has identified an equipment limitation ..." **The SDT agrees that Requirement R3 is basically administrative, but ensures the limitations (and associated changes in protection settings that affect the performance of a generating unit during a frequency or voltage excursion) are communicated to the appropriate planning and operating entities so that its performance can be correctly modeled.** 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. **The SDT agrees that an increase in the amount of time allowed for response is warranted. The SDT has changed the time period from 30 days to 60 days.** 4. Overall, this standard should address voltage and frequency relay settings only. **The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report which requires that the standard address performance.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
We Energies		a. Most generator voltage relaying is supplied from generator voltage transformers on the low-voltage side of the generator step-up transformer (GSU). It is necessary to provide the information needed for the Generator Owner to relate relay settings on the low-side of the GSU to the No Trip characteristic in Attachment 2, which is based on voltages on the GSU high-side. **The SDT agrees that generator protection normally senses the voltage at the generator terminals. Because there are many**

Organization	Yes or No	Question 8 Comment
		configurations of the connections of the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661-A and other international grid standards that are in effect. b. In Attachment 2, please clarify whether the No Trip zone includes the lines, similar to what was done in Attachment 1. **The no trip zone as depicted on the graph does include the lines (it is not permissible to trip if the voltage at the POI reaches 0.0 pu or if the continuous operating voltage is at 0.95 pu or 1.05 pu). The SDT expects that protection settings will be calculated to provide some margin from the absolute numbers on the curve (translated appropriately to the generator voltage level that the protection senses).**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PPL Electric Utilities and PPL Supply NERC Registered Organizations		a. A standard-specific definition of the word “plant” is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit’s behavior. **Individual generators and plants are not “registered” with NERC. The Applicability section states that the standard is applicable to Generator Owners. As such, all generating facilities that fall within the definition of the Registry Criteria fall within the scope of this standard.** b. Clarity is needed for the expression, “it does not trip,” in R1 and R2. Does this mean that the protective relaying does not trip, or that the unit does not trip? In the latter case do the requirements pertain only to interlocks, or do they also cover disturbances that may result in a trip? Such differentiations were clearly spelled-out in the PRC-005-2 draft currently out for voting, and they are needed here also. What seems at first to be relay-setting requirements may in fact also incorporate aux equipment drop-out, invoking for existing equipment the concerns stated above in

Organization	Yes or No	Question 8 Comment
		response to question 7 (with regard to designing a standard based on a technology for which vendors may not guaranty performance). **The wording of R1 (and R2) has been modified and, hopefully, clarifies the intent. The intention is that the relaying operate to trip the unit only when conditions are such that the frequency vs time characteristic (or voltage in R2) presented to the relay are described by the area outside of the "no trip zone" of Attachment 1 (2 for R2). It does not matter if the protection trips the generator directly or through a lockout relay or other auxiliary device.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Independent Electricity System Operator		a. Requirement R1: We believe the words "or generating plant" are missing at the end of R1 since the requirement addresses frequency protection relay settings for new or existing generating unit and generating plant. **The SDT has removed the words "or generating plant" from all of Requirement R1 for consistency in wording.** b. Requirement 4: In the last posting, we commented that:"We do not support the requirement to provide an estimate of the performance of the units during frequency and voltage excursions. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3, the TPs can apply the following relevant assumptions: (i) For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; (ii) For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping

Organization	Yes or No	Question 8 Comment
		takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? The SDT responded that "The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability." We do not agree that removing the 20% increment part goes far enough to achieve a good quality standard. In our view, based in argument put forth in our previous comments, the whole requirement does not add any value to reliability. We again suggest the SDT to remove this requirement altogether." **The SDT appreciates your position but was charged with meeting the recommendations of FERC Order 693 and the 2003 Blackout Report. Requirement R4 attempts to address a portion of the recommendation to provide better information to Transmission Planners regarding the performance of generating facilities during frequency and voltage excursions. This requirement is written such that the information is only provided if it requested by a planner. If the planner does not believe the information received would be of any value, it is permissible to not make the request.** c. Requirement R4.1, last sentence "If the Generator Owner expects the existing unit, generating plant will remain connected.....". We believe the "," before "generating plant" should read "or". **The SDT agrees that the wording was incorrect. Requirement R4 has been significantly modified and the intent of Parts 4.1 and 4.2 incorporated into the body of the requirement.** d. The proposed implementation plan for both standards conflicts with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of the sentences in Section A5, after "following applicable regulatory approval", of the two standards to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." **The phrase "following**

Organization	Yes or No	Question 8 Comment
		applicable regulatory authority" includes regulatory bodies from Canadian provinces requiring regulatory body approval. For clarity, the SDT modified the Implementation section and expanded the implementation description to more clearly show effective dates for those areas requiring regulatory approval and those areas that do not require regulatory approval.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
American Transmission Company, LLC		ATC recommends the SDT give consideration to the following:1. In Requirements R2 - the text refers to "non-protection system equipment" but this terminology is not defined. ATC recommends that the SDT provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. **The SDT agrees that this term was confusing. The term has been removed from Requirement R2 and the wording in Requirement R3 has been modified to more clearly indicate that limitations of the protection system do not qualify as a reason for exemption from portions of the no trip zones defined in Attachments 1 and 2.** 2. In Requirements, R3 - ATC recommends that the SDT add the requirement that the GO provides the expected duration of the limitation, if it is known. **In general, the SDT believes these limitations are permanent due to equipment design or regulatory considerations. The Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner may certainly inquire if they believe the Generator Owner is describing a temporary limitation.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
ACES Power Marketing Standards Collaborators		Because NERC has made clear that standards are enforced against the BPS and not the BES, the applicability section should be modified to state clearly that it applies to Facilities that are part of the BES. Otherwise small generators that do not affect reliability could be impacted by these standards. NERC enforcement has made this clear in response to comments on CAN-0016 that the CIP-001 standard applied only to the BES. They stated clearly: "According to Section 39 of the Energy Policy Act of

Organization	Yes or No	Question 8 Comment
		2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." **There is no mention of either BPS or BES in the Applicability section of this standard. The term "Bulk Electric System" is used within the Clarifications to Attachment 2.** Use of "new or existing" as a description for the generators in Requirements R1, R2 and R5 is confusing. What exactly constitutes new and why is it relevant? The requirements are performance requirements that apply to in-service generators so how does new help explain this further? The footnote in Requirement R5 only further confuses the situation since it is not included in Requirements R1 and R2. Part of the confusion likely centers around Requirement R5 applying to maintaining new generators frequency and voltage excursion performance as well as designing and building it. If "maintain" was removed from Requirement R5, we believe "new" could be removed from Requirement R1 and R2 and they essentially become the maintenance requirements. **The SDT agrees and has removed the words "new or existing" from both R1 and R2 and has revised Footnote 4 in Requirement R5** Furthermore, "new and existing" is not used consistently within other requirements such as Requirement R4. It is not obvious why it would not apply to Requirement R4 it if applies to Requirements R1 and R2. **The words "new and existing" were not used in Requirement R4. This requirement applies only to "existing" units because "new" units are expected to perform per Requirement R5.** Neither Requirement R1 nor R2 state within the main body of the requirement that the Parts are intended to be exceptions to the requirement. For clarity, there should be a statement (i.e. except when the Parts 1.1 and 1.2 are met) within the requirement that makes this clear. **The SDT agrees and has added wording identical to that in Requirement R2 to clarify that the sub parts are intended to be exceptions.** For Requirements R1 and R2, it is not clear if the sub-parts are the only reasons that allow for exceptions if other equipment limitations exceptions are allowed. Other equipment limitations should be allowed, and these requirements should be clarified to allow them. **It is stated in both Requirements R1 and R2 that equipment**

Organization	Yes or No	Question 8 Comment
		limitations (documented and communicated per Requirement R3) will allow tripping within portions of the no trip zones in Attachments 1 and 2. These statements have been moved into the sub parts of the two requirements for clarity. As written, Requirement R5 appears to be assumed to apply to a new generator in perpetuity. We draw this conclusion from the inclusion of "maintain" in the requirement. We think it makes more sense to have this requirement apply only to designing and building a new unit and then have the requirements that apply to existing units apply to the maintenance of the new units once they are established. The standard does not appear to allow "new" generating units to have frequency and voltage excursion performance limited by equipment. It should allow "new" equipment as it experiences normal wear and tear as well as damage for any other reasons to document its equipment limited frequency and voltage performance and communicate it similar to Requirements R1 through R3. Otherwise, a Geneator Operator with a "new" generator that has damaged equipment will be forced between operating the unit in a limited manner providing reliability support to the BES and possibly in violation of this standard or taking a forced outage to avoid violating the standard and experiencing escalated penalties for knowingly violating the standard. **The intent of Requirement R5 is to apply to "new" plants in perpetuity as you have described. If equipment aging or other conditions develop that clearly limit the generating plant's ability to ride through excursions and the owner is faced with performing maintenance that would not otherwise be needed in order to regain ride-through performance, Part 5.5 allows the Reliability Coordinator to grant an exemption if the RC believes the reliability improvement from having the generator operating or available outweighs the risk that it may not ride through an excursion.** We do not believe that Reliability Coordinator is the proper entity to grant a temporary exemption in Part 5.6. Rather, it is the Planning Coordinator that should grant the exemption. Furthermore, this is not consistent with other requirements such as Parts 2.1 and 2.1.1 that specify the Transmission Planner grant the exemption. Of course, Part 5.6 would not be necessary if Requirement R5 did not

Organization	Yes or No	Question 8 Comment
		deal with maintaining the unit and allowed the other requirements that apply to existing units to address maintenance. **It is the Reliability Coordinator that is responsible for the reliability of the transmission system, not the Planning Coordinator.** We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary. **The SDT agrees and has changed the VRF's for these three requirements to Medium.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
ERCOT		Comment 1: In the Applicability section, it is not clear in 4.2.3.2 which units/plants are required to meet this standard. For example, a generating plant that is greater than 75 MVA and consisted of 75 1MW generating units, is this generating plant required to meet MOD-026-1? Another example, a generating plant that is greater than 75 MVA and consisted of one 45MVA generating unit and two 15MVA generating unit, is only the 45MVA generating unit required to meet MOD-026-1?
Response: Thank you for your comments. Your comment refers to MOD-026. The SDT has refined Section 4.2.2 of the MOD-026 standard applicability to clarify that all units in a plant that meet the applicability are to be verified. Units that are less than 20 MVA can be verified utilizing either individual or aggregate model(s)		
Georgia Transmission Corporation		Comment on R6, Severe VSL.Time limit is within 60 calendar days, however the time limit for R3, R4 and R5 state 61 calendar days.Wording for Severe VSL for R3, R4, R5 and R6 should have the same time limitations of either "...within 61 calendar days" or revised so that the documentation was"communicated greater than 60 calendar

Organization	Yes or No	Question 8 Comment
		days....”.
Response: Thank you for your comments. The SDT agrees. The Severe VSL for Requirement R6 has been revised to address the issue you presented.		
Ingleside Cogeneration LP		Ingleside Cogeneration LP fully supports the goal to standardize voltage and frequency ride-through settings. In addition, we recognize the benefit to provide accurate generator modeling information and perform regular performance validations to system planners. However, such activities come at a price and compete for the same resources needed to support BES reliability in other ways.Furthermore, there is a cost to develop new PRC-024-1 compliant generation technologies - or to harden existing ones. This may improve reliability over the longer term, but could delay or even rule out the deployment of promising capabilities early on. These are all considerations that we know that the project team is aware of, but we will continue to point out the hidden costs of compliance wherever we believe that a justification of its advantages is not immediately obvious.
Response: Thank you for your comments. The SDT agrees that designing, building, and maintaining a generating facility to meet the performance requirement of Requirement R5 will be more expensive than building one without that capability. For this reason, the SDT is limiting the scope of the requirement to new facilities, with a six-year implementation schedule to allow designs to be developed, and is not requiring existing generating facilities to have to redesign and rebuild to accomplish the same level of performance.		
ISO New England Inc		ISO New England has comments on Requirement R2 and R3:R2Although the time duration is acceptable ISO-NE does not agree with the band shown. The band is shown as 0.95 p.u to 1.05 p.u at the point of interconnection. Parts of the New England system have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 pu to 1.05 pu. We also believe there are a number of other parts of the system outside of New England which would have similar concerns. Failure to make this change means that it is acceptable for generators to trip during steady state operation of the system on “low” voltage.

Organization	Yes or No	Question 8 Comment
		Unanticipated tripping of generators under steady state conditions could lead to significant reliability concerns on the system. **The voltage band applies to the point of interconnection of an operating generator. Other portions of a transmission system may be at significantly different voltages, but that would not give the generator an excuse to trip. If it is necessary to have an expanded band of normal operating voltage for a particular region, it can be mandated through a regional standard without imposing the same requirements on the entire continent.** R3The ISO would like to reiterate its previous comment that R3 is a significant concern. In the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the "No Trip Zone", there is no requirement to correct the issue. Instead, the generator must only document the limitation. This completely undermines the intent of this standard. There is no point to setting undervoltage relays to meet the curve if other equipment is still going to trip the plant. This standard appears to simply documenting system concerns rather than identifying and correcting them. **Requirements R1 and R2 apply to generator protection, not to the auxiliary systems. An "existing" generating facility may trip during a frequency or voltage excursion due to upsets caused by events on the auxiliary system (such as the cited contactor drop out). Requirement R4 is included in the standard to allow planning entities to obtain an estimate of such performance from the Generator Owner so the facilities can be appropriately modeled. The SDT does not believe it is realistic to require all "existing" generating facilities to be rebuilt to ensure performance to the level of Requirement R5.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Los Angeles Department of Water and Power		LADWP supports the following comment below:"The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency

Organization	Yes or No	Question 8 Comment
		requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan."
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
Lakeland Electric	Negative	LAK is a member of FMPA, please refer to their comments.
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons:1 - R1 - the facility interconnection document required through FAC-001 should supersede Attachment 1 in order to best address local area issues. R1 should be revised to specify this. **The SDT was charged with creating continent-wide requirements for frequency and voltage excursions and believes that consistency will not occur if various Transmission Service Providers apply various "no trip zones." Requirement R1, therefore, should not be dictated by FAC-001.** 2 - NERC IVGTF Task Force Document - the SDT should consider the recommendations from the NERC IVGTF Task Force 1.3 document. Specifically, the recommendations regarding clarifying the potential coordination issues between TPL-001 and PRC-024, clearly defining performance requirements for unbalanced and

Organization	Yes or No	Question 8 Comment
		balanced faults, and defining the performance required during and after disturbances and making clear and unambiguous statements as to what remaining "connected" entails (i.e. how much real power is expected to be delivered post disturbance and how long until the normal pre-disturbance power can delivered) should be considered. **The SDT reviewed the NERC IVGTF Task Force 1.3 document. Changes in the wording to Clarifications#2 and #5 to Attachment 2 have been made that address the concern with unbalanced and balanced faults. At this point, the SDT does not have a technical basis for defining requirements for performance during and after disturbances. Section 3.5.3 of the IVGTF document states, "A detailed power recovery characteristic for variable generators is not necessary to be specified in a standard."** 3 - Low Voltage Ride Through clarification - more information is required on the low voltage ride through curve. The GO should be required to provide unit outputs and ramp rates for the different voltage transitions and levels on the ride-through curve. **The SDT believes it the uncertainties involved in trying to determine generator outputs and ramp rates would not improve grid reliability.** 4 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. **The SDT agrees and has modified the wording in the Data Retention section of the standard to match that being used in other recently-approved NERC standards.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Nebraska Public Power District	Negative	Nebraska Public Power District (NPPD) supports the comments submitted through

Organization	Yes or No	Question 8 Comment
		the Midwest Reliability Organization (MRO) NERC Standards Review Forum (NSRF).
Dynegy		No
Omaha Public Power District	Negative	OPPD has singed on to MRO's NSRF comments
Puget Sound Energy		Our existing units capabilities are outside those required in the frequency attachment.
Response: Thank you for your comments. The SDT is pleased that your generating units will meet Requirement R1.		
Minnkota Power Coop. Inc.	Negative	Please see comments submitted by the MRO NSRF.
Lakeland Electric	Negative	Please see FMPA comments
MidAmerican Energy Co.	Negative	Please see MidAmerican and MRO NSRF Comments.
MidAmerican Energy Co.	Negative	Please see MidAmerican and NSRF comments.
MidAmerican Energy Co.	Negative	Please see MidAmerican and NSRF comments.
MidAmerican Energy Co.	Negative	Please see MidAmerican and NSRF comments.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Great River Energy	Negative	Please see MRO NSRF comments.
Fort Pierce Utilities Authority	Negative	Please see separately submitted formal comments by Florida Municipal Power Agency
Muscatine Power & Water	Negative	Please see the comments submitted by MRO NSRF

Organization	Yes or No	Question 8 Comment
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Beaches Energy Services	Negative	R2 - point of interconnection is confusing. We recommend putting the footnote into body of requirements and replace "point of interconnection" with "high side of GSU or collector bus" **The SDT believes Footnote 3 clearly explains the meaning of "point of Interconnection," as used in this standard.** R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the "grandfathering" of existing equipment lmimtations should still be in place. **The SDT does not intend the "equipment" to necessarily be plural. For that reason, the SDT said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be designed to meet the full range of the no trip zones in Attachments 1 and 2.** R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we

Organization	Yes or No	Question 8 Comment
		do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request, only changes to the settings that have been requested would need to be reported. The SDT has added the words "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).**
Response: Thank you for your comments. Please see the responses to specific comments above.		
American Electric Power		R2 is very "wordy", essentially a single run-on sentence which references yet additional material in its two footnotes, making it difficult to follow. This could be made more clear with the usage of bulleted items.R2.1.1 through R2.1.4 could be and perhaps should be R2.2 through R2.5. **The SDT agrees that Requirement R2 could be improved and has shortened the initial sentence by moving the reference to Requirement R3 to Part 2.6 and has restructured the other Parts as suggested.** R3: We recommend adding "known" to R3 such as "...shall document each known equipment limitation..." to make clear that a GO is not responsible for a cause they are not aware of. **The SDT has added the word "known" as for clarity as suggested, although the SDT believes the Generator Owner would not set its protection inside the no trip zone because of "unknown" limitations.** R3: The second point under R3 causes the limitation to expire with rating increases. Is a 10percent or more rating increase a realistic scenario and common enough to justify attention?10 percent seems arbitrary and this provision could pose a

Organization	Yes or No	Question 8 Comment
		hindrance to rating increasesthat may supply other reliability benefits. It may be advisable to remove this point. **The SDT agrees that ten percent is an arbitrary number. The SDT feels that if a Generator Owner is making enough of an investment in a facility to achieve a ten percent increase in rating, then any limitations caused by the equipment being upgraded should be eliminated. If AEP can provide a technical justification for a different number the SDT would be very interested.** R4.1 should include the Planning Coordinator in addition to the TP because the PC is responsible for UFLS coordination and assessment in PRC-006-1. **Requirement R4 has been extensively revised. It should be clearer now that the Planning Coordinator is one of the entities allowed to request the performance estimate from the Generator Owner.** R5.2 should be removed because of its obvious partiality toward wind farms. **Part 5.2 (now 5.1) gives an allowance for loss of up to 10% of units at a site with many small units which is analogous to a runback in power on a single larger unit.** R5.6 needs to include coordination with the Planning Coordinator because of the PC's responsibilities with respect to automatic UFLS. This should also perhaps include coordination with the Transmission Planner for exceptions on voltage excursion ride-through. **Both the Planning Coordinator and Transmission Planner are allowed to request a performance estimate from a Generator Owner in Requirement R4. The SDT believes this gives these entities access to the pertinent information.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Florida Municipal Power Agency		R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the “grandfathering” of existing equipment lmimtations should still be in place. **The SDT does not intend the “equipment” to necessarily be plural. For that reason, the SDT**

Organization	Yes or No	Question 8 Comment
		said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be specified to meet the full range of the no trip zones in Attachments 1 and 2. R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested would need to be reported. The SDT has added the words, "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).**
Response: Thank you for your comments. Please see the responses to your specific comments above.		

Organization	Yes or No	Question 8 Comment
City of Vero Beach		R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the "grandfathering" of existing equipment lmimtations should still be in place. **The SDT does not intend the "equipment" to necessarily be plural. For that reason, the SDT said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be specified to meet the full range of the no trip zones in Attachments 1 and 2.** R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested**

Organization	Yes or No	Question 8 Comment
		would need to be reported. The SDT has added the words, "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).
Response: Thank you for your comments. Please see the responses to your specific comments above.		
City of Green Cove Springs	Negative	R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the "grandfathering" of existing equipment lmimtations should still be in place. **The SDT does not intend the "equipment" to necessarily be plural. For that reason, the SDT said, "The equipment…" instead of "All equipment…" If there are multiple pieces of equipment that are causing limitations, only those that are replaced as a result of an upgrade would have to be specified to meet the full range of the no trip zones in Attachments 1 and 2.** R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. **There are no exceptions for "new" facilities in Requirements R1 and R2 because "new" facilities are expected to meet the performance requirements of Requirement R5. Part 5.2 (now 5.1) does allow up to 10% of a facility consisting of multiple small units to trip which is analogous to a power runback of a single large generator.** R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves. **The SDT assumes that the requestor would only ask for settings for the protection functions that are modeled for stability or UFLS**

Organization	Yes or No	Question 8 Comment
		performance. Typically, most generator protection functions are not included in these models. However, in order to predict the generators' behavior accurately, the entity creating the model must know the settings for all of the modeled protection functions, not just those that do not meet Requirements R1 or R2. Following such a request only changes to the settings that have been requested would need to be reported. The SDT has added the words, "unless otherwise directed" so that the requestor can indicate that future changes do not have to be reported (as may be the case for a one-time study that will not be repeated).
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Atlantic City Electric Company	Negative	Refer to comments submitted by Pepco Holdings Inc and Affiliates.
ReliabilityFirst		ReliabilityFirst votes in the affirmative for the the PRC-024-1 standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration:1. Requirement R5 and associated Subpart 5.1a. ReliabilityFirst believes there is a potential conflict and seeks clarification on the choice of words between Requirement R5 and associated Subparts 5.1 and 5.1.1. Requirement R5 begins by stating "Each Generator Owner shall design, build, and maintain its new unit or new generating plant..." which lends itself more to the "planning" type stages while Subpart 5.1 states "When the generating unit or generating plant is operating at or above the minimum sustainable generation threshold" which lends itself to actual "operation" of the unit. ReliabilityFirst questions how the conditions in Subpart 5.1 and 5.1.1 can be utilized if the actual "operation" of the unit has yet to be observed since Requirement R5 is dealing with the design stages of a new unit? **The SDT believes the design, construction, and maintenance of a generating facility are the key elements in assuring that the facility is able to remain connected to the grid during the excursions defined in the standard. There is really nothing that can be done operationally to prevent a generator from tripping if it has not been designed, built,**

Organization	Yes or No	Question 8 Comment
		and maintained correctly. There are, however, certain operating regimes (e.g. start-up and shut-down) when generating units are much less stable and less capable of remaining connected during an excursion. The SDT believes there is not a large reliability risk to allow a generator to trip if it is in this condition when an excursion occurs given the short term nature of operation in these regimes. 2. Requirement R6 a. ReliabilityFirst request further clarity regarding whether the parenthetical, "(that monitors or models the associated unit)," is associated with all the requesting entities listed in Requirement R6 (RC, PC, TOP, and TP) or just the TP. **The parenthetical refers to all four of the named entities.** 3. VSL Requirement R5 a. Requirement R5 states "Each Generator Owner shall design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion." The VSL states "The Generator Owner's generator tripped due to a Frequency Excursion within the no-trip parameters set forth in attachment 1". Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," the language in the requirement is not consistent with the associated VSL. It is not a violation of Requirement R5 if the generator tripped offline within the no-trip parameters, rather it is a violation if the GO failed to design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion. ReliabilityFirst recommends the following language for the "High" VSL, "The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a frequency excursion within the no-trip parameters set forth in Attachment 1. OR The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a voltage excursion within the no-trip parameters set forth in Attachment 1. **The VSL relates to Measure M5. The Measure relates to how the entity demonstrates that they have designed, built, and maintained the generating unit so that it does not trip during an excursion. Requirement R5 is written as a performance requirement. The words "design, build, and maintain" give the Generator Owners guidance as to how to achieve the performance**

Organization	Yes or No	Question 8 Comment
		objective. b. ReliabilityFirst also noted there is no mention of the Subparts 1.1 through 1.7 in the VSL (ReliabilityFirst understands that these are “Conditions and Exceptions” but they should somehow be incorporated into the VSLs. **VSL’s only apply when a violation of the requirement occurs. Parts 5.1 – 5.7 (now 5.1 – 5.6) are part of the requirement.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Gulf Power Company	Negative	See comments submitted via the electronic comments form by Antonio Grayson.
Dairyland Power Coop.	Negative	See MRO NSRF comments. In addition: The VSL must match the requirements of the standard. VSL R4 indicates a different calendar schedule than that of requirement R4. Requirement R4 indicates 60 calendar days after receipt of written request to provide information. VSL R4 indicates levels of severity less than 60 calendar days. **The SDT agrees and has revised the wording in the Requirement R4 VSL to address the issue.** Requirement R6 states "Each Generator Owner shall provide its generator protection trip settings to the...". Trip settings is open to interpretation. Please clarify what is meant by the term "trip settings", is meant to provide all trip settings or just specific trip settings. **The requesting entity will specify which protective functions he is modeling for which the trip settings (as opposed to settings that may be set to alarm only) must be reported. In this standard “trip” means disconnecting the generator from the transmission system.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
U.S. Army Corps of Engineers	Negative	See MRO/NSRF comments
Occidental Chemical	Negative	See submitted comments on behalf of Ingleside Cogeneration LP

Organization	Yes or No	Question 8 Comment
GenOn Energy		Thank you to the SDT for you efforts to produce a quality standards.R3 should be worded in a similar manner to R4. "The Generator Owner shall document the estimated equipment limitations..." The problem with a requirement like R3, is that documenting "each" equipment limitation on older facilities will contain uncertainties and unknowns. **The SDT has added the word "known" to qualify the equipment limitations for clarity, although the SDT does not see why a Generator Owner would set the protection system to operate inside the no trip zones due to unknown limitations.** The implementation schedule for the requirements will be more efficient if the schedule is aligned with the PRC-019 schedule rather than having the two similar efforts on different tracks. **The SDT agrees and has changed the implementation period, relative to Requirements R1, R2, R3, R4 and R6, of PRC-024-1 to match that of PRC-019.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Alberta Electric System Operator		The AESO does not support the changes made to the Curve Details, in the Voltage Ride-Through Curve Clarifications section of the standard, in particular the use of the term "base voltage" . In many parts of the Alberta transmission system the maximum normal operating voltages are significantly higher than 1.05pu of than the "base voltage" used in studies. The system has been studied, planned and designed around these higher voltages. For example; in a study the base (nominal) voltage is chosen to be one per unit (1.0 pu) equals 240 kV but in the study area typical operating voltages are 256 kV (1.07 pu) and can be as high as 1.10 pu.
Response: Thank you for your comments. The SDT has modified Clarification #1 to Attachment 2 by removing the words "base voltage" and "in the system models" and has replaced them with "nominal operating voltage" (specified by the Transmission Planner). The SDT believes this will address the different operating criteria used in different regions.		
Western Electricity		The Attachment depicting the No Trip Zone for frequency excursions for the WECC

Organization	Yes or No	Question 8 Comment
Coordinating Council		Interconnection is incorrect. It is missing one of the steps from the materials provided to the drafting team in July. The table is also missing a step. This must be corrected. In my opinion, the table identifying the High and Low Frequency Duration information is hard to interpret. As depicted, the table appears to be giving a range of time that a generator must stay interconnected at a specific frequency. I am not familiar with the requirements in other regions, but in WECC, we have specified a specific time that a generator must stay interconnected for a frequency range. In looking at the WECC table included int he draft standard I would not be able to discern how long a generator had to stay interconnected if the frequency were at 59.0 Hz. Similarly, I have the same problem with the information in the tables for the other interconnections. After discussions with drafting team representatives, an suggested revision for the format of the tables has been proveded to the drafting team for consideration.Even with the inclusion of the (not including the lines) statement on the No Trip Zone plot, it is still difficult to determine minute specifications from the plot. Depending on the quality of the diagram and the thickness of the line, there will still be the potential for debate. I believe a solution is to indicate the plot is for illusrative purposes only, and the specifics are provided in the tables. With the suggested format changes provided to the drafting team, there should be no room for speculation.Whether the Off-Nominal Frequency Capability Curve is used for illustrative purposes as suggested above, or for specifying details, it is difficult to view as presented. One option would be to provide three individual plots, one for each interconnection, and include them all as Attachment 2. This way you could still refer to Attachment A in Requirement R2, and perhaps add language such as "appropriate plot in Attachment 2" to the requirement.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.		
California Independent		The California Independent System Operator Corporation has adopted tariff requirements for generator frequency and voltage ride through capabilities that

Organization	Yes or No	Question 8 Comment
System Operator		apply to synchronous generators as well as requirements for generator frequency and voltage ride through capabilities that apply to asynchronous generators. As written, the requirements of draft PRC-024-1 apply to both synchronous and asynchronous generators. The ISO requests that the Generator Verification Standard Drafting Team confirm this reading of draft PRC-024-1, and suggests making this clarification in PRC-024-1 as well.
Response: Thank you for your comments. Under "Generator Owner" the Registry Criteria makes no distinction between synchronous and asynchronous generators. The SDT intends for both synchronous and asynchronous generators to be included as implied in the Registry Criteria and therefore made no specific distinction.		
Bonneville Power Administration		The curve depicting the "no trip zone" for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the "no trip zone" curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 1997 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also		

Organization	Yes or No	Question 8 Comment
been corrected.		
Consolidated Edison Co. of NY, Inc.		The definition of the terms Frequency Excursion and Voltage Excursion were deleted.All references to these terms should now be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use lower case terms.
Response: Thank you for your comments. The capitalization has been removed as suggested.		
Northeast Power Coordinating Council		The definitions of the terms Frequency Excursion and Voltage Excursion were deleted. All references to these terms should be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use the lower case terms. **The capitalization has been removed as suggested.** Regarding requirement R2, the time duration is acceptable. However, the band is shown as 0.95 per unit to 1.05 per unit at the point of interconnection, and there are areas of the power system that have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 per unit to 1.05 per unit. Failure to make this change means that it would be acceptable for generators to trip during steady state operation of the system on “low” voltage. Unanticipated and unncecessary tripping of generators under steady state conditions could lead to significant reliability concerns on the system. **The voltage band applies to the point of interconnection of an operating generator. Presumably, the generator would be holding that voltage within the scheduled voltage band provided by the Transmission Operator per VAR-001. Other portions of a transmission system may be at significantly different voltages, but that would not give the generator an excuse to trip. If it is necessary to have an expanded band of normal operating voltage for a particular region, it can be mandated through a regional standard without imposing the same requirements on the entire continent.** The PTs connected to the high voltage terminals of the GSU may not be used as a

Organization	Yes or No	Question 8 Comment
		source for generator protective relaying. Generator protective relays may be connected to the generator output terminals for their source of potential. The wording of R2 should incorporate generator terminals in addition to point of interconnection. **The SDT agrees that generator protection normally senses the voltage at the generator terminals. Because there are many configurations of the connections of the generators to the transmission systems, it is not practical to develop a single voltage curve defined at the generator terminals that equates to the voltage caused by an event on the transmission system. Each Generator Owner will have to determine how the transmission system event affects his specific generating units. This approach is consistent with FERC Order 661A and other international grid standards that are in effect.** Regarding R3, in the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the "No Trip Zone", there is no requirement to correct the issue. The generator must only document the limitation. This completely undermines the intent of this standard. It is counterproductive to set undervoltage relays to meet the curve if other equipment is still going to trip the plant for those same conditions. This standard appears to simply document system concerns rather than identify and correct them. **Requirements R1 and R2 apply to generator protection, not to the auxiliary systems. An "existing" generating facility may, indeed, trip during a frequency or voltage excursion due to upsets caused by events on the auxiliary system (such as the cited contactor drop out). Requirement R4 is included in the standard to allow planning entities to obtain an estimate of such performance from the Generator Owner so the facilities can be appropriately modeled. The SDT does not believe it is realistic to require all "existing" generating facilities to be rebuilt to ensure performance to the level of Requirement R5.** Under Requirement R5, 5.5 (exception) is unnecessary. It does not have to be stated that a generating unit or generating plant may trip if clearing a system fault necessitates disconnecting the generating unit or generating plant. **The SDT agrees that it is self-evident from a technical perspective, but is included for completeness**

Organization	Yes or No	Question 8 Comment
		for compliance auditing purposes.
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Duke Energy		The frequency and voltage ride-through curves are at the point of interconnection. Conditions inside a generating plant will depend upon how the generator responds to the transient. Models will have to be built and validated against plant-specific auxiliary equipment performance expectations.
Response: Thank you for your comments. The SDT assumes this comment is in reference to Requirement R4. The SDT does not require Generator Owners to do extensive dynamic simulations to determine performance. The SDT believes the Generator Owner could identify the most likely piece of equipment to fail to ride through (whether from contactor drop out or other mechanism) and estimate the time between that event and a generator trip due to the resulting process upset.		
MRO NSRF		The MRO NSRF believes that an entity having to attest to the fact that a generating unit or plant did not trip offers no foreseeable benefit to reliability. As currently stated, Measure M5 could be interpreted to mean that an entity would need to provide a letter of attestation each day or month a generating unit or plant were to function as intended. The MRO NSRF recommends the drafting team either remove this statement or else rephrase the Measure to avoid the expectation that entities verify normal operation. **The SDT agrees with your comment and has removed the wording that requires the attestation as evidence.** Additionally, as frequency excursion and voltage excursion are not NERC-defined terms nor terms to be defined as part of this project, recommend the terms be placed in lowercase letters to maintain consistency with the Requirement. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a FfrequencyEexcursion or VvoltageEexcursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip. **The SDT agrees**

Organization	Yes or No	Question 8 Comment
		with your comment. The capitalization has been removed as suggested. Please give consideration to the following suggestions:1. In Requirements R2 - the text refers to “non-protection system equipment” but this terminology is not defined. Provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. **The SDT has removed the term “non-protection system” from the wording in Requirement R2. In Requirement R3 the parenthetical has been revised so that it reads “(excluding limitations that are caused by generator frequency and voltage protective relays).”** 2. In Requirements, R3 - add the requirement that the GO provides the expected duration of the limitation, if it is known. . **In general, the SDT believes these limitations are permanent due to equipment design or regulatory considerations. The Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner may certainly inquire if they believe the Generator Owner is describing a temporary limitation.** 3. Request MOD-026 and MOD-027 be verified for redundancy with PRC-024.In the applicability section the only reference is to Generator Owner. It is recommended the applicability section include a statement that the affected units are only those that are a part of the Bulk Electric System. **The SDT does not believe MOD-026 or MOD-027 are redundant with PRC-024. The MOD standards require model validations where PRC-024 is a generator protective relaying setting and generator performance standard. The SDT feels that the applicable generators owned by a “Generator Owner” is clearly stated in the Registry Criteria and that no further clarification is required.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Kansas City Power & Light Co.	Negative	The proposed change to requirement 1.1 will allow for generator trips in operating conditions involving automatic load shedding action and increase the risk of taking the interconnection into a black out condition.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 8 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments. The allowance to trip for a specific rate of change of frequency that was specified in Requirement R1, Part 1.1 was provided so that any relaying added to protect from “Aurora” events would be allowed to trip the unit. The SDT investigated several major grid separation events and found that the rate of change of frequency during these events did not approach the 2.5 Hz/sec specified in the standard. However, it appears to the SDT that including the rate of change of frequency criterion in Requirement R1 is confusing industry and that “Aurora” protection is among the functions allowed to trip a generator due to impending or actual loss of synchronism or stability (Part 1.2 – now 1.1) and removed the rate of change of frequency criterion.</td></tr>
<tr><td>Public Utility District No. 1 of Lewis County</td><td>Negative</td><td>The standard does not list a minimum size generator that this standard applies to. Our utility has one plant with two small generators. The plant is near a project 10 times our size. We do not have the monitoring equipment to run this frequency or voltage testing. Therefore we must hire the work done. We get little or no benefit from the testing and money spent. Suggest the standard state a minimum generator size of 100 MVA that verification is required.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT feels that the applicable generators owned by a “Generator Owner” is clearly stated in the Registry Criteria and that no further clarification is required.</td></tr>
<tr><td>Southern California Edison Company</td><td></td><td>The standard should allow for wider regional variances - for example, WECC allows lower frequency and voltage excursions.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The WECC curve in Attachment 1 has been corrected per the 25 Nov 2007 WECC Coordinated Off Nominal Frequency Load Shedding Plan document. The table of associated values for the WECC region has also been corrected.</td></tr>
<tr><td>Northern Indiana Public Service Co.</td><td>Negative</td><td>There is a concern about inconsistencies between the Standards and Appendices</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT cannot address your concern without knowing the specifics of the inconsistencies to which you refer. Standard PRC-024 does not have any Appendices.</td></tr>
</table>

Organization	Yes or No	Question 8 Comment
Indiana Municipal Power Agency		This standard should concentrate on being a relay standard because it is not practical to include equipment limitations (excluding generator frequency and voltage protective relay equipment) that might trip the generating unit or generating plant offline. Just to figure out what the equipment limitations are at a generating plant an entity would have to perform a complete analysis and stability study on the generating plant including all auxiliary systems. If an entity cannot do this within it's organization, it will have to hire a contractor and/or outside consultant to inventory, test, and model the unit/plant. This type of analysis will be expensive and will come without any guarantees from the contractor that all the equipment limitations have been noted or discovered. In addition to the initial testing that a unit/plant will require to meet this standard, an entity will have to perform some type of routine testing and maintenance program in this area to ensure equipment characteristics have not changed enough to become a plant limitation (heat and age changes equipment characteristics). Based on this standard, entities will have to have equipment tested and built to certain specifications that will allow it to ride through a voltage and/or frequency excursion which will increase equipment and maintenance costs and could potentially limit equipment suppliers. One has to wonder if all of this cost will guarantee an increase in BES reliability that makes it worth paying for the work and equipment that will be needed for compliance (with the chance that the plant will still trip offline). In how many past instances has what this standard is trying to protect against been a proven issue? **The SDT agrees that studies will have to be done to design generating units (especially their auxiliary systems) to be able to ride through the types of transmission system voltage excursions defined in this standard. Since similar requirements are already in effect in parts of Europe and Asia, the SDT believes it is technically feasible.** There term "power conversion control equipmen"t is not defined and will allow entities to apply this term to different equipment which may or may not be correct. The SDT should take the time to define it now and not allow a CAN to define it. **There are a lot of terms that are not defined in the standard. The SDT prefers to refrain from adding definitions unless it is clear there is widespread confusion. You were**

Organization	Yes or No	Question 8 Comment
		the only entity to comment on this term. In this standard it refers to the electronics associated with asynchronous generator technologies. Measure five (M5) is currently written so that it appears that an entity will have to purchase a Digital Fault Recorder(s) for the unit/plant in order to produce the evidence needed to show a unit tripped offline (i.e. frequency rate of change greater than 2.5 Hz/sec) outside of the "no trip" zone. IMPA does not agree with this philosophy since the cost to purchase and install DFR's can be costly, especially to smaller entities. **Measure M5 does not require the purchase of any particular type of equipment. There are protective relays and voltage regulators with oscillographic recording capability. The Transmission Owner may already have a fault recorder in the substation. This requirement only applies to new units following a six-year implementation period to give time to budget for and design equipment to meet the requirement. In the event that it is determined that a fault recorder is the best option and does not exist in the substation the SDT believes the cost of adding a DFR as a percentage of the cost of building a new unit to be very small.** Why is 5.2 allowed for new units but not existing units**? Existing units are only required to set their protection systems such that they won't operate during an excursion as defined in the standard, but still may trip due to process upsets caused by the excursion. Requirement R5, however, does require new units to be designed to remain connected despite any process upsets. A generating unit may experience a power runback (which is allowed) and Part 5.2 (now 5.1) gives a facility with multiple small units an analogous allowance.** In 5.6, what makes the Mitigation Plan acceptable? Who needs to approve or make the Mitigation Plan acceptable. Where is the Mitigation Plan defined? IMPA believes the word "acceptable" should be removed. **The Reliability Coordinator has the discretion to determine if the plan to address the limitation that is submitted by a Generator Owner is acceptable. The SDT believes Part 5.6 (now 5.5) is worded correctly.**

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. Please see the responses to your specific comments above.		
PSEG		We have these additional comments:a. In Part 4.1 of R4, the first sentence has this proposed change, indicated by capilatization: "An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection [deleted "described by"] THAT WAS DEVELOPED FROM A dynamic simulation provided by the Transmission Planner. **The SDT agrees and has revised the wording in Requirement R4.** b. M5 is confusing. M5 states "Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a Frequency Excursion or Voltage Excursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip."i. Frequency Excursion and Voltage Excursion are capitalized terms - the previous version's defined terms were supposed to be removed. **The SDT agrees with your comment. The capitalization has been removed as suggested.** ii. While is appears that an "attestation that the generating unit or generating plant did not trip" is only required for a unit or plant that remained on line during a frequency or voltage excursion, the language should be made clearer. **The SDT agrees with your comment. The language referring to attestations has been removed.** iii. We suggest that the GVSDT consider rewording M5 to clearly state what trips should be reported, whether non-trips that occur during frequency and voltage excursions are to be reported, and what supporting evidence (or attestations) is required for each reported item. A table may be the best way to display this. **Measure M5 does not reference reporting non-trips during an excursion. Thus these events do not need to be reported. By default, the generating unit is compliant if it did not trip, whether there was an excursion or not.**

Organization	Yes or No	Question 8 Comment
		Finally, M5 should be developed to produce the VSL metric for R5. **The SDT believes that the VSL does cover both the Requirement its associated Measure.** c. The previously defined terms "Frequency Excursion" and "Voltage Excursion" were to be removed from this draft; however they are used in R4 and in the VSL table. The GVSDT should search the standard for all such usage and correct it. **The capitalization has been removed as suggested.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		
Gainesville Regional Utilities	Negative	We support FMPA's position on this matter.
Southwest Power Pool Standards Development Team		We would suggest revision of M5 to read. Also since the two terms Frequency Excursion and Voltage Excursion are no longer to be defined by this project we would ask that you use the lower case for these terms in the standard. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied.
Response: Thank you for your comments. The capitalization has been removed and reference to the attestation that the unit did not trip has been removed as suggested.		
PacifiCorp		While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
Response: Thank you for your comments. The SDT appreciates the support for the reliability goals. We would add that it will		

Organization	Yes or No	Question 8 Comment
require changes in auxiliary system configuration and equipment as well as the turbine and generator manufacturers' inputs to achieve the goal.		
Exelon Corp.		The Off Normal Frequency Capability Curve should consist of separate tables for each Interconnect to make it easier to read. **There are already separate data tables for each curve on Attachment 1. The SDT does not believe adding more graphs would add clarification.** Exelon still feels that Footnote 1 belongs in the Applicability section of the standard. Suggest that the Applicability section be revised to state "GO shall set applicable protective relaying so as not to impact R1.1, R1.2, R1.3, R1.5 unless exempted by non-protection system equipment limitations per the exclusion criteria. **The SDT respectfully disagrees. In PRC-024-1, Footnote 1 is intended for clarification purposes only to make it clear that the standard does not force the GO to install voltage or protective relays if they are not already installed on its unit(s).** It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the "no trip zone." If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions. **Relays that are known to drift from their settings should either be calibrated more frequently or set such that a tolerance is built into the relay setting so that the drift will not cross the "no trip zone" boundary.**
Response: Thank you for your comments. Please see the responses to your specific comments above.		

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed (August 18, 2007).
5. First Draft of MOD-024-2 was posted for comment January 18 – February 18, 2010. MOD-024-2 was later combined with MOD-025-1 to form MOD-025-2.
6. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011

Proposed Action Plan and Description of Current Draft:

This is the second draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and initial ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop second version draft standard.	July 2011 – February 2012
2. Post response to comments and conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.	March - April 2012
3. Develop responses to ballot comments.	April - June 2012
4. Post response to comments and conduct successive ballot.	June 2012
5. Develop responses to ballot comments.	June - July 2012
6. Post responses to comments and conduct recirculation ballot.	August 2012
7. BOT adoption.	September 2012
8. File with regulatory authorities.	November 2012

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Owner with synchronous condenser

4.2. Facilities:

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.

4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.

4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, one calendar year following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.

5.1.2 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.1.3 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.5 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, one calendar year following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.3. Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site.

B. Requirements

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify the Reactive Power capability of its generating units and the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data

C. Measures

M1. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, and will have evidence that it submitted the information and a correction for ambient conditions, if requested, within 90 days to its Transmission Planner; such as dated electronic mail messages, mail receipts, or dated information collected and used to complete attachments, in accordance with Requirement R1.

M2. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, and will have evidence that it submitted the information within 90 days to its Transmission

Planner; such as dated electronic mail messages, mail receipts, or dated information collected and used to complete attachments, in accordance with Requirement R2.

M3. Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages, mail receipts, or dated information collected and used to complete attachments, in accordance with Requirement R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the latest data and evidence to show compliance as identified below, and the previous set of evidence if updated since the last compliance audit unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Real Power capability and submitted the data but was missing 1 to 33 percent of the data. OR	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, from the of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Real Power capability and submitted the data but was missing 33 to 66 percent of the data. OR	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Real Power capability and submitted the data but was missing 67 to 99 percent of the data. OR	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner failed to verify the Real Power capability of an applicable generating unit. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than

	The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	75 calendar months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.
R2	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180

	Transmission Planner more than 90 calendar days, but within 120 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability and submitted the data but was missing 1 to 33 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.	Planner more than 120 calendar days, but within 150 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR	Planner more than 150 calendar days, but within 180 calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR	calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner failed to verify the Reactive Power capability of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar

	OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	months.
R3	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, from the date the of verification by staged test or the date of the historical operating data that was selected for verification.	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR	The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner failed to verify the Reactive Power capability of an applicable synchronous condenser unit.

	OR The Transmission Owner verified the Reactive Power capability and submitted the data but was missing 1 to 33 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month	The Transmission Owner verified the Reactive Power capability and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar	The Transmission Owner verified the Reactive Power capability and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal	OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.

	requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	months but less than or equal to 14 calendar months.	to 15 calendar months.	

E. **Regional Variances**

None

F. **Associated Documents**

Version History

Version	Date	Action	Change Tracking
Version 1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06
Version 2	TBD	Revised per SAR for Project 2007-09 and combined with MOD-024-1	TBD

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that is expected to affect its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date.

It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below. If an applicable Facility is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour.

2.4. Collect the under-excited Reactive Power capability verification data identified in 2.1 and 2.2, and the over-excited Reactive Power capability verification data identified in 2.2 as soon as a limit is reached.

2.5. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.6. Collect the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator.

3.3. The voltage at the high and low side of the GSU and/or system Interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature

- Relative humidity
- Cooling water temperature

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system Interconnection transformer(s) tap setting.

3.7. The GSU transformer losses if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary Load(s), provide an engineering estimate and associated calculations.

Note 1: Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. Observe auxiliary bus voltage limits. The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: It is desired that the automatic voltage regulator be in service when testing a generator’s reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator.

Note 4: The verification is intended to define the limits of the unit’s capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

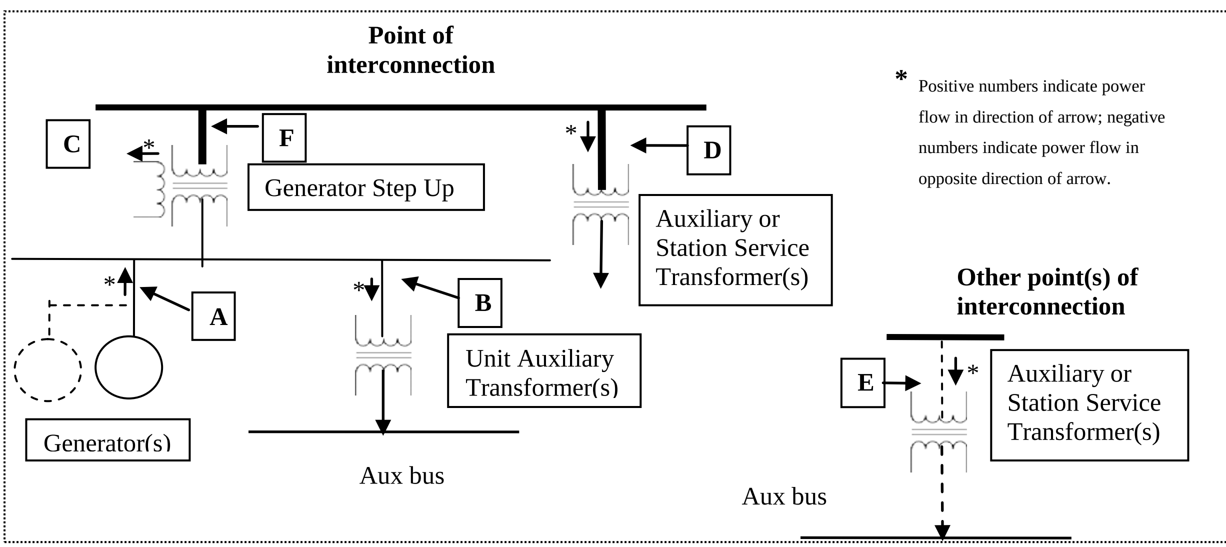
Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

Check all that apply:

- ☐ Over-excited Full Load Reactive Power Verification
- ☐ Under-excited Full Load Reactive Power Verification
- ☐ Over-excited Minimum Load Reactive Power Verification
- ☐ Under-excited Minimum Load Reactive Power Verification
- ☐ Real Power Verification
- ☐ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	kV	MW	Mvar	Sum multiple generators that are verified together

				or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary yransformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data)
Gross Reactive Power Generating Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Generating Capability (*MW)		N/A
Aux Real Power (*MW)		N/A
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		N/A
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Tap Settings: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end of the verification period:

  Air temperature: _________

  Humidity: _________

  Cooling water temperature: _________

  Others as applicable: _________

- The recorded Mvar values were adjusted to rated generator voltage, where applicable.
- Generator hydrogen pressure (if applicable) ______________
- Date that data shown in last verification column in table above was taken ______________

Remarks :

Note: If the verification value did not reach the Thermal Capability Curve (D-Curve), describe the reason.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps ~~-~~Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed ~~on~~ (August 18, 2007).
5. First Draft of MOD-024-2 was posted for comment January 18 – February 18, 2010. MOD-024-2 was later combined with MOD-025-1 to form MOD-025-2.
6. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011

Proposed Action Plan and Description of Current Draft:

This is the ~~first~~second draft of the proposed ~~revision to this~~ standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels~~. This first posting;~~ and is being submitted for a ~~30~~45-day concurrent formal comment period~~.~~ and initial ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. ~~Post first~~Develop responses to comments and develop second version draft ~~revision of~~ standard.	~~April-May~~July 2011 – February 2012
2. Post response to comments and ~~second version draft revision of~~conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.	~~July – August 2011~~March - April 2012
3. ~~Post response to comments and request authorization~~Develop responses to ballot ~~the revised standard~~comments.	~~September - October 2011~~April - June 2012
4. ~~Conduct initial~~Post response to comments and conduct successive ballot.	~~November 2011~~June 2012
5. ~~Post response~~Develop responses to ballot comments.	~~December 2011~~June - July 2012
6. ~~Conduct~~Post responses to comments and conduct recirculation ballot.	~~January~~August 2012
7. BOT adoption.	~~February~~September 2012

8. File with regulatory authorities.	~~March~~November 2012

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure ~~that planning entities have~~ accurate information on generator gross and net Real and Reactive Power capability ~~data when assessing~~and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

   4.1. Functional entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner with synchronous condenser

   4.2. Facilities:

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit ~~or synchronous condenser >~~greater than 20 MVA (gross nameplate rating) ~~in a generating Facility~~directly connected ~~at the point of interconnection at 100 kV or above~~to the bulk power system.

   ~~**4.2.1**~~**4.2.2** Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.

   ~~**4.2.2**~~**4.2.3** Generating plant/Facility ~~>~~greater than 75 MVA (gross aggregate nameplate rating) ~~and~~directly connected ~~at~~to the ~~point of interconnection at 100 kV or above~~bulk power system.

   ~~**4.2.3** Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.~~

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, one calendar year following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 20~~%~~ percent of its applicable ~~units~~Facilities.

   5.1.2 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 40~~%~~ percent of its applicable ~~units~~Facilities.

5.1.3 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 60~~%~~ percent of its applicable ~~units~~Facilities.

5.1.4 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 80~~%~~ percent of its applicable ~~units~~Facilities.

5.1.5 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified 100~~%~~ percent of its applicable ~~units~~Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, one calendar year following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 20~~%~~ percent of its applicable ~~units~~Facilities.

5.2.2 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40~~%~~ percent of its applicable ~~units~~Facilities.

5.2.3 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60~~%~~ percent of its applicable ~~units~~Facilities.

5.2.4 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80~~%~~ percent of its applicable ~~units~~Facilities.

5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100~~%~~ percent of its applicable ~~units~~Facilities.

5.3. Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site.

B. Requirements

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real ~~and~~Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~1.1.~~2.1. Verify the Reactive Power capability of its generating units and ~~shall verify~~ the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1~~—~~.

~~1.2.~~ ~~Record the information on~~Submit a completed Attachment 2 (~~-~~or ~~on the Generator Owner's~~a form ~~that contains~~containing the same information as identified in Attachment 2~~);~~

~~1.3.~~2.2. ~~Submit~~) to its Transmission Planner within 90 calendar days of either the date the data is recorded ~~to its Transmission Planner~~for a staged test or the date the data is selected for verification using historical operational data.

~~R2.~~R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Rective Power capability of its applicable Facilities as follows: *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: Long-term Planning]*

~~2.1.~~3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1~~;~~.

~~2.2.~~ ~~Record the information on~~Submit a completed Attachment 2 (or ~~on the Transmission Owner's~~a form ~~that contains~~containing the same information as identified in Attachment 2)

~~2.3.~~3.2. ~~Submit~~ to its Transmission Planner within 90 calendar days of either the date the ~~verification to its Transmission Planner.~~ data is recorded for a staged test or the date the data is selected for verification using historical operational data

C. Measures

M1. Each Generator Owner ~~has~~will have evidence that it performed the verification, such as a completed ~~MOD-025~~ Attachment 2 or the Generator Owner form with ~~equivalent~~the same information, and ~~has~~will have evidence that it submitted the information~~,~~ and a correction for ambient conditions, if requested, within 90 days to its Transmission

Planner; such as dated electronic mail messages ~~or~~, mail receipts, or dated information collected and used to complete attachments, in accordance with Requirement R1.

M2. Each ~~Transmission~~Generator Owner ~~has~~will have evidence that it performed the verification, such as a completed ~~MOD-025~~ Attachment 2 or ~~Transmission~~ the Generator Owner form with ~~equivalent~~the same information, and ~~has~~will have evidence that it submitted the information~~,~~ within 90 days to its Transmission Planner; such as dated electronic mail messages ~~or~~, mail receipts, or dated information collected and used to complete attachments, in accordance with Requirement R2.

M3. Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages, mail receipts, or dated information collected and used to complete attachments, in accordance with Requirement R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

~~**Data**~~

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the latest data ~~or~~and evidence to show compliance as identified below, and the previous set of evidence if updated since the last compliance audit unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for ~~Requirement 1, Measure 1~~Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement ~~2~~R3, Measure ~~2~~M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found ~~non-compliant~~noncompliant, it shall keep information related to the ~~non-compliance~~noncompliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance ~~Audits~~Audit

Self-~~Certifications~~Certification

Spot Checking

Compliance ~~Violation Investigations~~Investigation

Self-Reporting

~~Complaints~~

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real ~~and Reactive~~ Power capability of its applicable generating unit ~~or applicable synchronous condenser~~, but submitted the data to its Transmission Planner more than 90 calendar days, but within ~~100~~120 calendar days, from the date of verification by staged test or the date of the historical operating data that was ~~recorded~~selected for verification. OR The Generator Owner verified the Real Power capability and submitted the data but was missing 1 to 33 percent of the data.	The Generator Owner verified and recorded the Real ~~and Reactive~~ Power capability of its applicable generating unit ~~or applicable synchronous condenser~~, but submitted the data to its Transmission Planner more than ~~100~~120 calendar days, but within ~~110~~150 calendar days, from the of verification by staged test or the date ~~the~~of the historical operating data that was ~~recorded~~selected for verification. OR The Generator Owner verified the Real Power capability and submitted the data but was missing 33 to 66 percent of the data.	The Generator Owner verified and recorded the Real ~~and Reactive~~ Power capability of its applicable generating unit ~~or applicable synchronous condenser~~, but submitted the data to its Transmission Planner more than ~~110~~150 calendar days, but within ~~120~~180 calendar days, of the date of verification by staged test or the date of the historical operating data that was ~~recorded~~selected for verification. OR The Generator Owner verified the Real Power capability and submitted the data but was missing 67 to 99 percent of the data.	The Generator Owner verified and recorded the Real ~~and Reactive~~ Power capability of its applicable generating unit ~~or applicable synchronous condenser~~, but submitted the data to its Transmission Planner more than ~~120~~180 calendar days from the date of verification by staged test or the date of the historical operating data that was ~~recorded~~selected for verification. OR The Generator Owner failed to verify the Real ~~and Reactive~~ Power capability of an applicable generating unit. OR The Generator Owner ~~failed to~~

	OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	~~verify~~performed the ~~Reactive Power capability of an applicable synchronous condenser unit~~verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR ~~The Generator Owner failed to submit its verified Real or Reactive Power capability for an applicable generating unit or an applicable synchronous condenser unit to its Transmission Planner.~~ The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.
R2	The Generator Owner verified and recorded the Reactive Power capability	The Generator Owner verified and recorded the Reactive Power capability of	The Generator Owner verified and recorded the Reactive Power capability of its	The Generator Owner verified and recorded the Reactive Power capability of its applicable

	of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability and submitted the data but was missing 1 to 33 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in	its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.	applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.	generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner failed to verify the Reactive Power capability of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12

	more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.
~~R2~~R3	The Transmission Owner verified and recorded the Reactive Power capability of its ~~applicable~~ applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within ~~100~~120 calendar days, from the date the of verification by staged test or the date of the historical	The Transmission Owner verified and recorded the Reactive Power capability of its applicable ~~applicable~~ synchronous condenser, but submitted the data to its Transmission Planner more than ~~100~~120 calendar days, but within ~~110~~150 calendar days, from the date of verification by staged test or the date of the historical	The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than ~~110~~150 calendar days, but within ~~120~~180 calendar days, of the date of verification by staged test or the date of the historical operating data that was	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner failed to

	operating data that was ~~recorded~~selected for verification. OR The Transmission Owner verified the Reactive Power capability and submitted the data but was missing 1 to 33 percent of the data. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner	operating data that was ~~recorded.~~selected for verification. OR The Transmission Owner verified the Reactive Power capability and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the verification	~~recorded.~~selected for verification. OR The Transmission Owner verified the Reactive Power capability and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for	verify the Reactive Power capability of an applicable synchronous condenser unit. OR ~~The Transmission Owner failed to submit its verified Reactive Power capability for an applicable synchronous condenser unit to its Transmission Planner.~~ The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.

	performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	

E. **Regional Variances**

None

F. **Associated Documents**

Version History

Version	Date	Action	Change Tracking
Version 1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06
Version 2	TBD	Revised per SAR for Project 2007-09 and combined with MOD-024-1	TBD

MOD-025 ~~-~~Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

~~For units of less than 20 MVA~~

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that is expected to affect its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date.

It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below. If an applicable Facility is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).

2. ~~Perform verification~~Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification~~, and~~. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification~~.~~ (see Note 3 if the automatic voltage regulator is not available). Operational data from within the ~~year~~two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as ~~it~~that operational data meets the criteria in 2.1 through 2.5 below and is ~~within 20% of the expected value:~~at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. ~~Perform verification of~~Verify Real ~~and~~Power capability, Reactive Power capability ~~of all generating units at maximum~~ over-excited (lagging) and Reactive Power capability under-excited (leading) ~~reactive capability at rated gross~~ of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power ~~capability~~[1] at the time of the verifications. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of ~~reactive~~ Reactive Power capability of wind turbines and photovoltaic inverters with ~~ninety~~at least 90 percent of the wind turbines or photovoltaic inverters at a site on--line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as ~~possible~~practical, Real and Reactive Power output during ~~verification~~verifications.

2.2. Verify Reactive Power capability of all ~~generating units~~Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they ~~could~~are normally ~~be~~ expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. Conduct the ~~rated~~maximum Real Power and ~~overexcited~~over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour.

2.4. ~~Record~~Collect the under-excited ~~reactive~~Reactive Power capability verification data ~~required~~identified in 2.1 and 2.2, and the over-excited ~~reactive~~Reactive Power capability verification data ~~required~~identified in 2.2 as soon as a limit is reached.

2.5. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.6. Collect the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer.

3. Record the following data for the ~~verification~~ verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator.

~~[1] The generating unit's normal expected maximum Real Power at the time of the verification.~~

3.3. The voltage at the high and low side of the ~~generator step-up~~GSU and/or system ~~interconnection~~Interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient ~~air temperature~~conditions, if applicable, at the end of the verification period ~~and a correction factor, if any, to allow~~ the ~~Transmission~~Generator Owner requires to perform corrections to ~~correct the~~ Real Power ~~rating to a~~for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- ~~3.4.~~ Cooling water temperature ~~if needed.~~

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing ~~generator step-up~~GSU and/or system ~~interconnection~~Interconnection transformer(s) tap setting.

3.7. The GSU transformer losses if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include ~~generator step-up~~GSU and/or system ~~interconnection~~Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific ~~reactive~~Reactive auxiliary ~~load~~Load(s), provide an engineering estimate and associated calculations.

~~5. The periodicity for performing Real and Reactive Power generating capability verification is as follows:~~

~~5.1. For staged verification; verify each generator and/or synchronous condenser or plant/facility at least every five years, (with no more than 66 calendar months between verifications), or within one year of the discovery of a change that is expected to affect its Real Power or Reactive Power capability by more than 10% of the last reported verified capability and is expected to last more than six months.~~

~~5.2. For verification using operational data; verify each generator and/or synchronous condenser or plant/facility at least every five years, within 66 calendar months between verifications, or within one year following the discovery of a change that is expected to affect its Real Power or Reactive Power capability by more than 10% of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, the Generator Owner shall designate one of the dates as the verification date, and report that date as the verification date on MOD-025- Attachment 2 for periodicity purposes.~~

~~5.3. For either verification method, new units shall be verified within one year of their commercial operation date.~~

Note 1: ~~The~~Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard ~~may~~will not duplicate the manufacturer supplied thermal capability curve (D-curve~~) due to transmission system conditions.~~). However, the verification required by the standard~~ may be able to ~~, even when conducted under these transmission system conditions, may uncover ~~unit~~applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc~~.~~., which could be further analyzed for resolution. ~~For any verification limited by transmission system conditions, the~~Observe auxiliary bus voltage limits. The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner's database; nor is it likely this value will agree with data required to be submitted by ~~the~~ MOD-010~~ standard~~.

Note 2: While not required by the standard, it is desirable to perform engineering ~~analysis~~analyses to determine expected ~~unit~~applicable Facility capabilities under less restrictive system ~~conditions~~voltages than those encountered during the verification. Even though this analysis will not verify the complete MVAR capability curve, it provides a reasonable estimate of ~~unit~~applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator.

Note 4: The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

MOD-025 Attachment 2

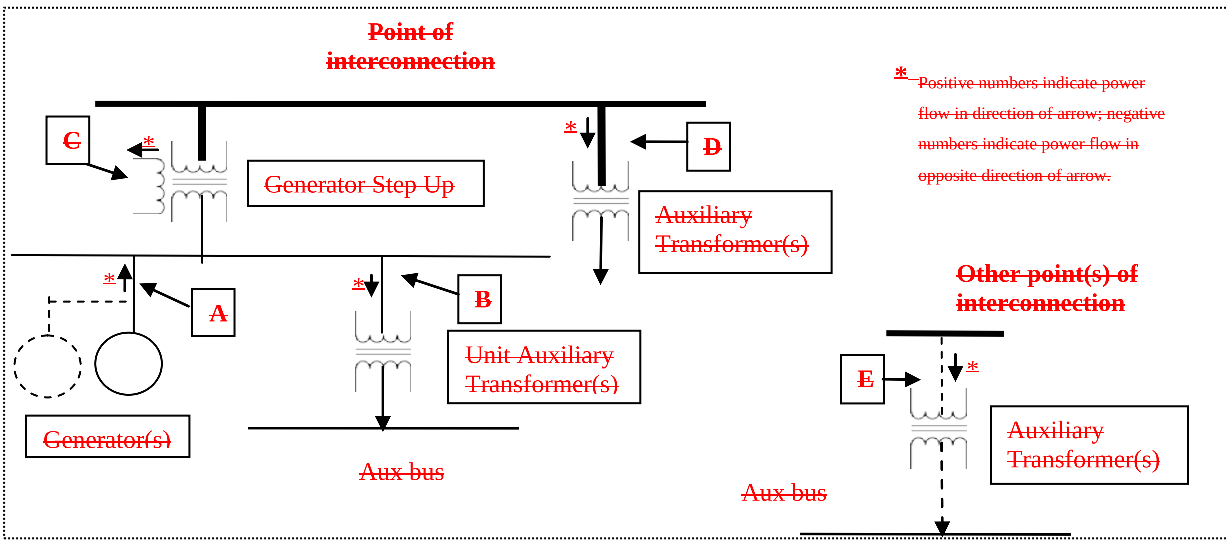
One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the ~~generation facility~~applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025 ~~Attachement,~~ Attachment 1) is reported.

Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

Check all that apply:



☐ Over-excited Full Load Reactive Power Verification

☐ Under-excited Full Load Reactive Power Verification

☐ Over-excited Minimum Load Reactive Power Verification

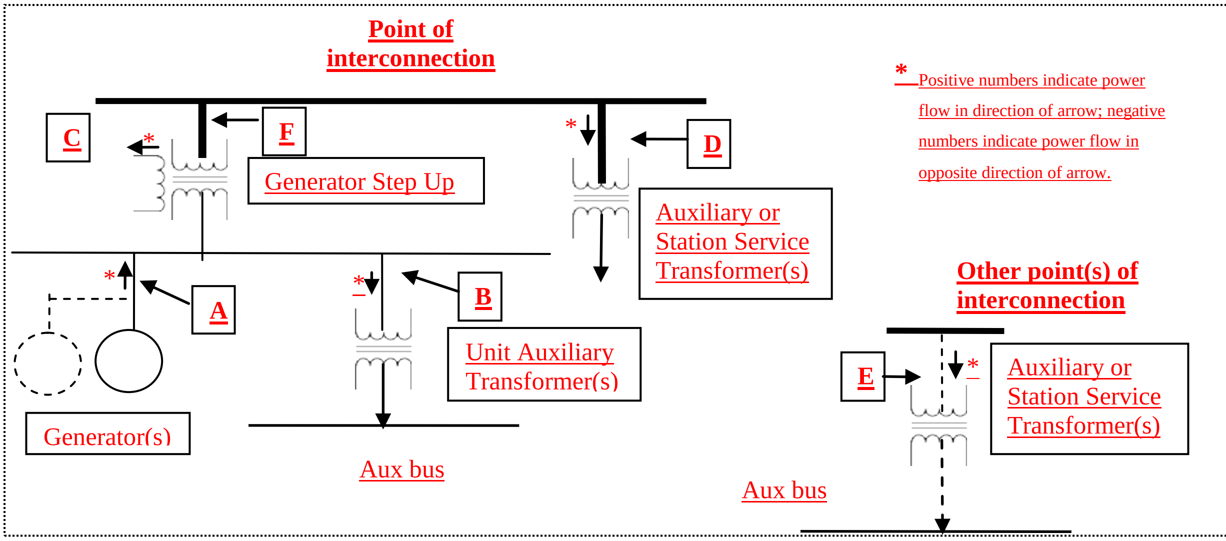
☐ Under-excited Minimum Load Reactive Power Verification

☐ Real Power Verification

☐ Staged Test Data

☐ Operational Data

Simplified one-line diagram showing plant auxiliary ~~load~~Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	kV	MW	~~MVAR~~Mvar	Sum multiple ~~Generators~~generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit.
Identify ~~values that are~~ calculated values, if any:				
B	kV	MW	~~MVAR~~Mvar	Sum multiple ~~Unit Auxiliary Transformers~~unit auxiliary transformers.
Identify ~~values that are~~ calculated values, if any:				
C	kV	MW	~~MVAR~~Mvar	Sum multiple tertiary ~~load~~Loads, if any.
Identify ~~values that are~~ calculated values, if any:				
D	kV	MW	~~MVAR~~Mvar	Sum multiple ~~Auxiliary Transformers~~auxiliary and station service transformers.
Identify ~~values that are~~ calculated values, if any:				
E	kV	MW	~~MVAR~~Mvar	If multiple points of ~~interconnection~~Interconnection, describe these for accurate modeling; report points individually (~~Sum~~sum multiple ~~Auxiliary Transformers~~auxiliary yransformers).
F	kV	MW	Mvar	Net unit capability
Identify ~~values that are~~ calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data)
Gross Reactive Power Generating Capability (*~~MVAR~~Mvar)		
Aux Reactive Power (*~~MVAR~~Mvar)		
Net Reactive Power Capability (*~~MVAR~~Mvar) equals Gross Reactive Power Capability (*~~MVAR~~Mvar) minus Aux Reactive Power ~~(*MVAR~~connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Generating Capability (*MW)		N/A
Aux Real Power (*MW)		N/A
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		N/A

* Note: Enter values at the end of the verification period.

GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Tap Settings: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient ~~air temperature~~conditions at the end of the verification period:

  Air temperature: ~~__________°F Include in remarks below, any correction factor for different temperatures.~~__________

  Humidity: __________

  Cooling water temperature: __________

  Others as applicable: __________

- The recorded ~~MVAR~~Mvar values were adjusted to rated generator voltage, where applicable.

- ~~Most recent~~Generator hydrogen pressure (if applicable) ______________
- Date that data shown in last verification ~~Date used~~column in table above was taken ______________

~~Check all that apply:~~

- ~~☐ Overexcited Full Load Verification~~
- ~~☐ Underexcited Full Load Verification~~
- ~~☐ Overexcited Minimum Load Verification~~
- ~~☐ Underexcited Minimum Load Verification~~
- ~~☐ Real Power Verification~~

Remarks :

Note: If the verification value did not reach the Thermal Capability Curve (D-Curve), describe the reason.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Approvals Required

MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Transmission Owner with synchronous condenser
Generator Owner

Facilities

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.
- Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.
- Generating plant/facility > 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the next calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable units.

- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

In those jurisdictions where regulatory approval is not required:

- By the first day of the next calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable units.
- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20 percent of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20 percent annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site.

It is the intent of *ReliabilityFirst* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the *ReliabilityFirst* Reliability Standards Development Procedure will be followed for any such revisions or retirements.

Retirements

MOD-024-1 - Verification of Generator Gross and Net Real Power Capability and MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability should both be retired at midnight of the day immediately prior to the Effective Date of MOD-025-2 in the particular jurisdiction in which the new standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Approvals Required

MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Approvals

None

Revisions ~~to Approved Standards and Definitions~~Glossary Terms

None

~~Replace all requirements of MOD-025-1 and retire all requirements of MOD-024-1.~~

~~Compliance with the Standard~~

Applicable Entities and Facilities ~~The following entities are responsible for being compliant with all requirements of MOD-025-2:~~

- Transmission Owner with cynchronous condenser
- Generator Owner
- Facilities
  - Individual generating unit ~~>~~ greater than 20 MVA (gross nameplate rating) ~~in a generating facility connected at the point of interconnection at 100 kV or above~~directly connected to the bulk power system.
  - Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.
  - Generating plant/facility > 75 MVA (gross aggregate nameplate rating) ~~and connected at the point of interconnection at 100 kV or above~~directly connected to the bulk power system.

- ~~Blackstart Resources units, regardless of size that are included in a Blackstart Capability Plan.~~
- ~~Synchronous condensers greater than or equal to 50 MVA.~~

Conforming Changes to Other Standards
None

Effective Date

In those jurisdictions where regulatory approval is required:

- By the first day of the next calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20~~%~~ percent of its applicable units.
- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40~~%~~ percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60~~%~~ percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80~~%~~ percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100~~%~~ percent of its applicable units.

In those jurisdictions where regulatory approval is not required:

- By the first day of the next calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20~~%~~ percent of its applicable units.
- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40~~%~~ percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60~~%~~ percent of its applicable units.

- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80~~%~~ percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100~~%~~ percent of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20~~%~~ percent of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20~~%~~ percent annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site.

It is the intent of *ReliabilityFirst* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the *ReliabilityFirst* Reliability Standards Development Procedure will be followed for any such revisions or retirements.

Retirements

MOD-024-1 - Verification of Generator Gross and Net Real Power Capability and MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability should both be retired at midnight of the day immediately prior to the Effective Date of MOD-025-2 in the particular jurisdiction in which the new standard is becoming effective.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011

Proposed Action Plan and Description of Current Draft:

This is the second draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and initial ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop second version draft standard.	July 2011 – February 2012
2. Post response to comments and conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.	March - April 2012
3. Develop responses to ballot comments.	April - June 2012
4. Post response to comments and conduct successive ballot.	June - July 2012
5. Develop responses to ballot comments.	August - September 2012
6. Post responses to comments and conduct recirculation ballot.	October 2012
7. BOT adoption.	November 2012
8. File with regulatory authorities.	December 2012

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control and Active Power/Frequency Control Functions
2. **Number:** MOD-027-1
3. **Purpose:** To verify that the turbine/governor and load control and active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, that accurately represent generator unit real power response to system frequency variations.
4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of this standard, the term “applicable Facility” is considered, “applicable units[2].” Units or plants with an average capacity[3] factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following:

4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating):
    - o Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings)

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[1] Turbine/governor and load control and active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to variable energy plants.

2 Applicable generating units do not include startup or standby units not normally connected to the grid.

3 Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

4.2.2 Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant or generating Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.3 Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant or generating Facility comprised of individual generating units less than 20 MVA (gross nameplate ratings)

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following applicable regulatory approval.

5.1.2 Each Generator Owner shall ensure at least 25 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, three years following applicable regulatory approval.

5.1.3 Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following applicable regulatory approval.

5.1.4 Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following applicable regulatory approval.

5.1.5 Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following applicable regulatory approval.

5.2. In those jurisdictions where no regulatory approval is required:

5.2.1 Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following Board of Trustees adoption.

5.2.2 Each Generator Owner shall ensure at least 25 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, three years following Board of Trustees adoption.

5.2.3 Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following Board of Trustees adoption.

5.2.4 Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following Board of Trustees adoption.

5.2.5 Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Planner shall provide the following instructions and model data to its requesting Generator Owner within 90 calendar days of receiving a request for those instructions or model data: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of acceptable turbine/governor and load control and active power/frequency control system models for use in dynamic simulation.
- Instructions on how to obtain the Transmission Planner’s software manufacturer’s dynamic turbine/governor and load control and active power/frequency control system model library block diagrams and/or data sheets.

- Model data for any of the Generator Owner's existing unit or plant specific turbine/governor and load control and active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) model(s).

R2. Each Generator Owner shall provide, for each of its applicable units, a verified turbine/governor and load control and active power/frequency control model including documentation and data as specified in Parts 2.1 and 2.2, to its Transmission Planner (within 365 calendar days from the date that the response was recorded) in accordance with the periodicity specified in MOD-027 Attachment 1, to ensure modeling data is accurate for use in simulation software. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Perform verification using one or more models acceptable to the Transmission Planner that include(s) the following information:

2.1.1. Documentation comparing the applicable unit's model response to the recorded response for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line, a speed governor reference change with the unit on-line, or from a partial load rejection test[4].

2.1.2. Type of governor and load control and active power control/frequency control equipment.

2.1.3. A description of the turbine (e.g. for Hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer).

2.1.4. Model structure and data for turbine/governor and load control and active power/frequency control.

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

2.2. For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA, perform verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit.

[4] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on load data under the normal operating conditions under which the model is expected to apply

The written response shall contain either the technical basis for maintaining the current model, or the model changes, or a plan to perform model verification[5] (in accordance with Requirement R2): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Written notification, from its Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control and active power/frequency control model is not “usable”, or
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control and active power/frequency control model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the predicted turbine/governor and load control and active power/frequency control response did not approximate the recorded response for three or more transmission system events.

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[5] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic[6]. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the turbine/governor and load control and active power/frequency control system verified model information whether the model is useable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable; and shall include a technical description if the model is not useable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The turbine/governor and load control and active power/frequency control function model initializes to compute modeling data without error.

5.2. A no-disturbance simulation results in negligible transients.

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control and active power/frequency control model exhibiting positive damping.

C. Measures

M1. Evidence for Requirement R1 must include the transmitted instructions or data and dated evidence of transmission of requested instructions and data, such as dated

[5] If verification is performed, the 10 year period as outlined in Attachment 1 is reset.

[6] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

electronic mail messages, dated postal receipts, dated confirmation of facsimile transmission.

M2. Evidence for Requirement R2 must include, for each of the Generator Owner's applicable Facilities, the verification report showing that the turbine/governor and load control and active power/frequency control model was verified and dated evidence of transmission, ,such as a dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmission as specified in Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal, such as a dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmission.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's Facilities for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal, such as dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmittal.

M5. Evidence of Requirement R5 must include, for each model received, the dated response containing the information required in Parts 5.1 through 5.3 and dated evidence of transmittal, such as dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmittal.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest and previous turbine/governor and load control and active power/frequency control system model verification evidence of Requirement R2, Measure M2.

- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 181 calendar days of receiving a request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 30 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1. OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified turbine/governor and load control and active power/frequency control model(s) more than 90 calendar days late or failed to provide the verified model(s) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Subpart 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.

R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice. (R3)	The Generator Owner failed to provide a written response within 181 calendar days of receiving notice as specified in Requirement R3. OR The Generator Owner’s written response was provided within 181 calendar days of receiving written notice. However the Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic. (R4)	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 271 calendar days of making changes to the turbine/governor and load control and active power/frequency control system that altered the equipment response characteristic as specified in Requirement R3.
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable (including a technical description if the model is not useable) more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R5)	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable (including a technical description if the model is not useable), more than 120 calendar days but less than 150 calendar days of receiving the verified model information. (R5)	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable (including a technical description if the model is not useable) more than 150 calendar days but less than 180 calendar days of receiving the verified model information. (R5)	The Transmission Planner failed to provide a written response to the Generator Owner within 181 calendar days of receiving the verified model information as specified in Requirement R5. OR The Transmission Planner provided a written response without including

		OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	confirmation of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control and active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005
3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004
4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004
5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004
6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

7) P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-027 Attachment 1

Turbine/Governor and Load Control and Active Power/Frequency Control Model Periodicity

Periodicity Determination Supporting Criteria
Criteria 1: Unit Model Verification Frequency Excursion Criteria: • ≥ 0.05 hertz deviation from scheduled frequency for the Eastern Interconnection with the applicable unit operating in a frequency responsive mode • ≥ 0.10 hertz deviation from scheduled frequency for the ERCOT and Western Interconnections with the applicable unit operating in a frequency responsive mode • ≥ 0.15 hertz deviation from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode **Criteria 2: Establishing the Initial Ten Year Unit Verification Period Start Date:** **For each applicable unit, the initial start date is set to either of the 25 percent, 50 percent, 75 percent, or 100 percent Standard Implementation Effective Dates established for compliance in accordance with the nine calendar year transition period.** **Criteria 3: Establishing the Recurring Ten Year Unit Verification Period Start Date:** **The start date is the actual data collection date for the most recently performed applicable unit verification.** **Criteria 4: For the purpose of calculating the initial ten year unit verification period 25 percent, 50 percent, 75 percent or 100 percent threshold for generation fleet compliance, equivalent unit MVA is included (reference 4th row in the following table).** **Consideration for Early Compliance** **Existing turbine/governor and load control and active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:** • **The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.** • **The Generator Owner has an existing verified model that is compliant with the requirements of this standard.**

Event Triggering Verification	Verification Periodicity	Comments
Establishing the initial verification period (Criteria 2) for an applicable unit (Requirement R2)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1 on or after the Standard Implementation Effective Date. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test before or on the Standard Implementation Effective Date	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded. Criteria 4 applies when calculating generation fleet compliance during the 9-year transition period
Subsequent verification for an existing applicable unit	Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit's ten year anniversary date of the collection of the recorded unit Real Power response used for the current validation. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test on or before the applicable unit's ten year anniversary date of the collection of the recorded unit Real Power response used for the current validation.	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed with settings final	Record unit Real Power response to the first frequency excursion event that meets Criteria 1	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that

Event Triggering Verification	Verification Periodicity	Comments
(Requirement R2)	OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the commissioning date	the response was recorded.
Existing applicable unit that is equivalent to another operating unit(s) at the same physical location AND Each equivalent applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each equivalent applicable unit has identical applicable components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Verify a different equivalent unit during each ten year verification period.	Document circumstance with a written statement and include with the verified model and documentation and data provided to the Transmission Provider for the verified equivalent unit. Criteria 4 applies when calculating generation fleet compliance during the 9-year transition period.
Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period AND Neither an on-line speed governor reference test nor a partial load rejection test was performed. (Requirement R2)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1after the ten year verification period	Document circumstance with a written statement. Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.

Event Triggering Verification	Verification Periodicity	Comments
Existing applicable unit control system response is altered resulting in an alteration of the response of the turbine/governor and load control or active power/frequency control model AND The Generator Owner has submitted a verification plan. (Requirement R4)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
The Generator Owner receives written comments including dated electronic or hard copy evidence indicating that the recorded turbine/governor and load control or active power/frequency control response for three or more transmission system events did not match the predicted control system model response. AND The Generator Owner has submitted a verification plan. (Requirement R3)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the unit Real Power response was provided as part of the dated evidence.
The Generator Owner receives written comments detailing technical concerns with the Generator Owner's turbine/governor and load control and active power/frequency control model verification documentation. AND The Generator Owner has submitted a verification plan (Requirement R3)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.

Event Triggering Verification	Verification Periodicity	Comments
The Turbine/governor and load control and active power/frequency control model identified as unusable by the Transmission Planner. AND The Generator Owner has submitted a verification plan. (Requirement R3)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date that of the submitted verification plan	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
New or existing applicable unit is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.) OR New or existing applicable unit has a disabled control system	Not required until responsive control mode operation for connected operations is established.	Document circumstance with a written statement. Perform verification per the periodicity specified in Row 3 for a “New Generating Unit” (or new equipment) once responsive control mode operation for connected operations is established.
New or existing applicable unit does not have an installed control system	Not required until unit has an installed control system	Document circumstance with a written statement. Perform verification per the periodicity specified in Row 3 for a “New Generating Unit” (or new equipment) once responsive control mode operation for connected operations is established.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps ~~-~~Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011

Proposed Action Plan and Description of Current Draft:

This is the ~~first~~second draft of the ~~this~~proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels~~. This first posting~~; and is being submitted for a ~~30~~45-day concurrent formal comment period~~.~~ and initial ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. ~~Post first~~Develop responses to comments and develop second version draft ~~revision of~~ standard.	~~April-May~~July 2011 – February 2012
2. Post response to comments and ~~second version draft revision of~~conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.	~~July – August 2011~~March - April 2012
3. ~~Post response to comments and request authorization~~Develop responses to ballot ~~the revised standard~~comments.	~~September - October 2011~~April - June 2012
4. ~~Conduct initial~~Post response to comments and conduct successive ballot.	~~November 2011~~June - July 2012
5. ~~Post response~~Develop responses to ballot comments.	~~December 2011~~August - September 2012
6. ~~Conduct~~Post responses to comments and conduct recirculation ballot.	~~January~~October 2012
7. BOT adoption.	~~February~~November 2012

8. File with regulatory authorities.	~~March~~December 2012

A. Introduction

1. Title: Verification of Models and Data for Turbine/Governor and Load Control ~~or~~and Active Power/Frequency Control ~~-~~Functions

2. Number: MOD-027-1

3. Purpose: To verify that the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] model and the model parameters, used in dynamic ~~simulation~~simulations that assess Bulk Electric System (BES) reliability, that accurately represent generator unit real power response to system frequency variations.

4. Applicability:

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of this standard, the ~~following Facilities are~~term "applicable Facility" is considered, "applicable units[2]." Units or plants with an average capacity[3] factor greater than 5~~%~~ percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following:

4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- ~~Each~~Individual generating unit ~~with a~~ greater than 100 MVA (gross nameplate rating ~~greater than 100 MVA,~~) directly connected ~~at~~to the ~~point of interconnection[4] at greater than 100 kV~~bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with ~~a~~ total generation greater than 100 MVA (gross aggregate ~~nameplate~~ rating ~~greater than 100 MVA, connected at the same point of interconnection at greater than 100 kV:~~):

[1] Turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control:

a. Turbine/governor and ~~Load~~load control applies to conventional synchronous generation.

b. Active power/frequency control applies to variable energy plants.

2 Applicable generating units do not include startup or standby units not normally connected to the grid.

[~~3~~]3 Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

[4] ~~The common transmission bus voltage level at which the generator step up transformer is connected.~~

- o Each individual generating unit ~~with a~~ greater than 20 MVA (gross nameplate rating ~~greater than 20 MVA;~~); and
- ~~o The remainder of the plant as an aggregate.~~
- o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.2 Generating units connected to the Western Interconnection with the following characteristics:

- ~~Each~~Individual generating unit ~~with a~~ greater than 75 MVA (gross nameplate rating ~~greater than 75 MVA,~~) directly connected ~~at~~to the ~~point of interconnection[3] at greater than 100 kV~~bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with ~~a~~ total generation greater than 75 MVA (gross aggregate ~~nameplate~~ rating ~~greater than 75 MVA, connected at the same point of interconnection t greater than 100 kV:~~):
  - o -Each individual generating unit ~~with a gross nameplate~~ greater than 20 MVA~~;~~ (gross nameplate rating); and
  - ~~o The remainder of the plant as an aggregate.~~
  - o Each generating plant or generating Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

4.2.3 Generating units connected to the ERCOT Interconnection with the following characteristics:

- ~~Each~~Individual generating unit ~~with a~~ greater than 50 MVA (gross nameplate rating ~~of greater than 50 MVA,~~) directly connected ~~at~~to the ~~point of interconnection[3] with rating greater than 100 kV~~bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with ~~a~~ total generation greater than 75 MVA (gross aggregate ~~nameplate~~ rating ~~of greater than 75 MVA, connected at the same point of interconnection at greater than 100 kV:~~):
  - o Each individual generating unit ~~with a gross nameplate~~ greater than 20 MVA~~;~~ (gross nameplate rating); and
  - ~~o The remainder of the plant as an aggregate.~~
  - o Each generating plant or generating Facility comprised of individual generating units less than 20 MVA (gross nameplate ratings)

5. Effective Date:

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 ~~By~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following applicable regulatory approval~~:~~.

- **5.1.2** ~~At~~Each Generator Owner shall ensure at least 25~~%~~ percent of ~~each Generator Owner's~~its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, three years following applicable regulatory approval.

  - ~~100% compliant with Requirements R1, and R3 through R5.~~

~~5.1.2~~**5.1.3** ~~By~~Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following applicable regulatory approval~~:~~.

- ~~At least 50% of each~~Each Generator ~~Owner's~~Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2~~.~~

~~5.1.3~~**5.1.4** ~~By~~ by the first day of the first calendar quarter, seven years following applicable regulatory approval~~:~~.

- ~~At least 75% of each~~Each Generator ~~Owner's~~Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2~~.~~

~~5.1.4~~ ~~By~~ by the first day of the first calendar quarter, nine years following applicable regulatory approval~~:~~

- **5.1.5** ~~100% of each Generator Owner's applicable units compliant with Requirement R2~~.

5.2. In those jurisdictions where no regulatory approval is required:

5.2.1 ~~By~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following Board of Trustees adoption~~:~~.

- **5.2.2** ~~At~~Each Generator Owner shall ensure at least 25~~%~~ percent of ~~each Generator Owner's~~its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, three years following Board of Trustees adoption.

  - ~~100% compliant with Requirements R1, and R3 through R5.~~

~~5.2.2~~**5.2.3** ~~By~~Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following Board of Trustees adoption~~:~~.

- ~~At least 50% of each~~Each Generator ~~Owner's~~Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2~~.~~

~~5.2.3~~5.2.4 ~~By~~ by the first day of the first calendar quarter, seven years following Board of Trustees adoption~~:~~.

- ~~At least 75% of each~~Each Generator ~~Owner's~~Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2~~.~~

~~5.2.4~~5.2.5 ~~By~~ by the first day of the first calendar quarter, nine years following Board of Trustees adoption~~:~~.

- ~~100% of each Generator Owner's applicable units compliant with Requirement R2.~~

B. Requirements

R1. Each Transmission Planner shall provide ~~its Generator Owner with~~ the following instructions and model data to its requesting Generator Owner within ~~30~~90 calendar days of receiving a request ~~from its Generator Owner~~ for those instructions ~~and~~or model data: *[Violation Risk Factor: Lower] [Time Horizon: ~~Long-term~~Operations Planning]*

- Instructions on how to obtain the list of acceptable turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system models for use in dynamic simulation.
- Instructions on how to obtain the Transmission Planner's software manufacturer's dynamic turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system model library block diagrams and/or data sheets.
- ~~Any~~Model data for any of the Generator Owner's existing unit or plant specific turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system ~~data~~ contained in the Transmission Planner's dynamic database from the current (in-use) model(s).

R2. Each Generator Owner shall provide, for each of its applicable units, a verified turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] model ~~(for each of its applicable Facilities)~~including documentation and data as specified in Parts 2.1 and 2.2, to its Transmission Planner (within 365 calendar days from the date that the response was recorded) in accordance with the periodicity specified in MOD-027 Attachment 1, to ensure modeling data is accurate for use in simulation software ~~subject to the following:~~. *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: Long-term Planning]*

2.1. ~~Each Generator Owner shall perform its verifications with~~ Perform verification using one or more models acceptable to ~~its~~the Transmission Planner that ~~collectively~~ include(s) the following information:

2.1.1. Documentation ~~from the turbine/governor and Load control or active power/frequency control[1]~~comparing the applicable unit's model ~~verification activities including the on-line~~ response ~~compared~~ to the recorded response for either a frequency excursion from a system disturbance~~, or~~ that meets Attachment 1 Criteria 1 with the unit on-line, a ~~frequency~~ speed governor reference change~~.~~ with the unit on-line, or from a partial load rejection test[5].

2.1.2. Type of governor and ~~Load~~load control ~~or~~and active power control/frequency control equipment.

2.1.3. A description of the turbine (e.g. for Hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer).

2.1.4. ~~Turbine~~Model structure and data for turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control~~[1] model structure and data~~.

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, ~~Load~~and load control~~, etc.~~ but excluding AGC control) ~~which~~that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

2.2. For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA, perform verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5

R3. Each Generator Owner shall provide a written response ~~that contains~~to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit. The written response shall contain either the technical basis for maintaining the current model, ~~a list of future~~or the model changes, or a plan to perform model verification[6] ~~to its Transmission Planner within 90 calendar days of receiving written notice of one of the following:~~(in accordance with Requirement R2): *[Violation Risk Factor: Lower] [Time Horizon: ~~Long-term~~Operations Planning]*

- Written notification, ~~including a technical description~~ from its Transmission Planner ~~of why~~(in accordance with Requirement R5) that the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control~~[1]~~ model is not "usable~~" as identified in Requirement R5, Parts 5.1 through 5.3 criteria,~~", or

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[5] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on load data under the normal operating conditions under which the model is expected to apply

[6] If verification is performed, the 10 year period as outlined in Attachment 1 is reset.

- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control and active power/frequency control model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the predicted turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] response did not ~~match~~approximate the recorded response for three or more transmission system events.

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[6] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system that alter the equipment response [7] characteristic[8]. *[Violation Risk Factor: Lower] [Time Horizon: ~~Long-term~~Operations Planning]*

R5. Each Transmission Planner shall ~~determine if the model meets the criteria identified in Requirement R5, Parts 5.1 through 5.3 and provide a written response to~~notify the Generator Owner ~~indicating whether the model is useable or not useable; including a technical description if the model is not useable. This written response shall be submitted~~ within 90 calendar days of receiving the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system verified model information~~.~~ whether the model is useable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable; and shall include a technical description if the model is not useable. *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: ~~Long-term~~Operations Planning]*

5.1. The turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] function model ~~can initialize~~initializes to compute modeling data without error.

5.2. A no-disturbance simulation results in negligible transients.

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] model exhibiting positive damping.

C. Measures

~~**M1.** The Transmission Planner shall have~~ Evidence for Requirement R1 must include the transmitted instructions or data and dated evidence ~~to show that it provided~~ of transmission of requested instructions and data ~~(such as dated electronic mail messages or mail receipts) within 30 calendar days of receiving a request as specified in Requirement R1.~~

~~[7] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).~~

[8] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

M1. ~~Each Generator Owner shall have evidence (~~, such as dated electronic mail messages ~~or mail receipts) including~~, dated postal receipts, dated confirmation of facsimile transmission.

M2. Evidence for Requirement R2 must include, for each of the Generator Owner's applicable Facilities, the verification report ~~to show~~showing that ~~it provided~~ the ~~verified~~ turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] ~~model as specified~~ model was verified and dated evidence of transmission, ,such as a dated electronic mail messages, dated postal receipts, or dated confirmation of facsimile transmission as specified in Requirement R2.

~~**M2.**~~ Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement ~~R2.~~

M3. ~~Each Generator Owner shall have~~R3 and dated evidence ~~to show that it provided a written response (~~of transmittal, such as a dated ~~copy of the response, dated~~ electronic mail messages ~~or mail~~, dated postal receipts~~) containing identified information and submitted within 90 calendar days of receiving any written notification as specified in Requirement R3~~, or dated confirmation of facsimile transmission.

M4. ~~Each~~Evidence for Requirement R4 must include, for each of the Generator ~~Owner shall have~~Owner's Facilities for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence ~~to show that it provided a written response (~~of transmittal, such as dated electronic mail messages ~~or mail~~, dated postal receipts~~) submitted within 180 calendar days of making system changes specified in Requirement R4~~, or dated confirmation of facsimile transmittal.

M5. ~~Each Transmission Planner shall have~~Evidence of Requirement R5 must include, for each model received, the dated response containing the information required in Parts 5.1 through 5.3 and dated evidence ~~to show that it provided a written response (~~of transmittal, such as dated electronic mail messages ~~or mail~~, dated postal receipts~~) within 90 calendar days of receiving the model as specified in Requirement R5~~, or dated confirmation of facsimile transmittal.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest and previous turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control~~[1]~~ system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance ~~Audits~~Audit

Self-~~Certifications~~Certification

Spot Checking

Compliance ~~Violation Investigations~~Investigation

Self-Reporting

~~Complaints~~

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 181 calendar days of receiving a request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 30 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, ~~Parts~~Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1. OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, ~~Parts~~Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, ~~Parts~~Subparts 2.1.1, through 2.1.5.	The Generator Owner ~~failed to provide~~provided its verified turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] model(s) more than 90 calendar days late or failed to provide the verified model(s) ~~no more than 90 calendar days late~~ to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, ~~Part~~Subpart 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts

				identified in Requirement R2, ~~Parts~~Subparts 2.1.1, through 2.1.5.
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice. (R3)	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice. (R3)	The Generator Owner failed to provide a written response within 181 calendar days of receiving notice as specified in Requirement R3. OR The Generator Owner's written response was provided within 181 calendar days of receiving written notice~~ however~~. However the Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system that alter the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system that alter the equipment response characteristic. (R4)	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system that alter the equipment response characteristic. (R4)	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 271 calendar days of making changes to the turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system that ~~alter~~altered the equipment response ~~-~~characteristic as specified in Requirement R3.
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable~~;~~ (including a technical description if the model is not useable~~,~~) more than 90 calendar days but less than 120 calendar	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable~~;~~ (including a technical description if the model is not useable~~,~~), more than 120 calendar days but less than 150 calendar days of receiving the verified model	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable~~;~~ (including a technical description if the model is not useable~~,~~) more than 150 calendar days but less than 180 calendar days of receiving the verified model	The Transmission Planner failed to provide a written response to the Generator Owner within 181 calendar days of receiving the verified model information as specified in Requirement R5. OR

	days of receiving verified model information. (R5)	information. (R5) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	information. (R5) OR The Transmission Planner provided a written response within 181 calendar days to the Generator Owner however the written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner provided a written response ~~within 181 calendar days to the Generator Owner however the written response omitted~~without including confirmation ~~for~~of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3~~.~~

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and ~~Load~~load control ~~or~~and active power/frequency control[1] system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES General Meeting 2007, paper 07GM1307
2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005
3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004
4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004
5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004
6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

7) P. Pourbeik, C. Pink and R. Bisbee, "Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data", Proceedings of the IEEE PSCE, March, 2011

MOD-027 Attachment 1

Turbine/Governor and Load Control ~~or~~and Active Power/Frequency Control Model Periodicity

~~Note that local grid codes may specify shorter time frames.~~

~~Facility~~	~~Condition~~ Periodicity Determination Supporting Criteria	~~Periodicity~~

Criteria 1: Unit Model Verification Frequency Excursion ~~Threshold~~Criteria:

- **≥ 0.05 hertz deviation from scheduled frequency for the Eastern Interconnection~~, or~~ with the applicable unit operating in a frequency responsive mode**
- **≥ 0.10 hertz deviation from scheduled frequency for the ERCOT and Western Interconnections~~, or~~ with the applicable unit operating in a frequency responsive mode**
- **≥ 0.15 hertz deviation from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode**

~~from scheduled frequency.~~

Criteria 2: Establishing the ~~Recurring~~Initial Ten Year Unit Verification Period Start Date:

For each applicable unit, the initial start date is set to either of the 25~~%,~~ percent, 50~~%,~~ percent, 75~~%,~~ percent, or 100~~%~~ percent Standard ~~implementation~~Implementation Effective Dates established ~~as required~~ for compliance in accordance with the nine calendar year transition period. ~~or~~

Criteria 3: Establishing the Recurring Ten Year Unit Verification Period Start Date:

The start date is ~~set to~~ the actual data collection date for the most recently performed applicable unit verification.

Criteria 4: For the purpose of calculating the initial ten year unit verification period 25 percent, 50 percent, 75 percent or 100 percent threshold for generation fleet compliance, equivalent unit MVA is ~~performed~~included (reference 4th row in the following table).

Consideration for Early Compliance

Existing turbine/governor and load control and active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- **The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.**
- **The Generator Owner has an existing verified model that is compliant with the requirements of this standard.**

~~Existing Generating Unit~~	~~During each ten year unit verification period as established by Criteria 2 above.~~ ~~**AND**~~ ~~**No exceptions** apply.~~ ~~**AND**~~ ~~While the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to at least one BES frequency excursion as specified in Criteria 1 above.~~	~~A recorded unit Real Power response for a frequency excursion shall be collected during a ten calendar year (January - December) period with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected.~~
~~Existing Generating Unit~~	~~During each ten year unit verification period as established by Criteria 2 above.~~ ~~**AND**~~ ~~**The following unit exception** applies:~~ ~~1) Multiple units have the same MVA nameplate rating that are ≤ 350 MVA **AND**~~ ~~2) The same multiple units have identical applicable components and settings **AND**~~ ~~3) The same multiple units are sited at the same physical location **AND**~~ ~~4) The model for one of these equivalent units has been verified.~~	~~Not Required (however, perform verification on a different unit each ten calendar year cycle).~~
~~Existing Generating Unit~~	~~An acceptable frequency excursion at the generator from scheduled frequency **does not** occur during the ten calendar year (January - December) period and a staged frequency reference test is not performed~~ ~~**AND**~~ ~~The first time after the ten calendar year period while the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active~~	~~The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected.~~

	~~power/frequency control mode response and is subjected to a BES frequency excursion as specified in Criteria 1 above.~~	
~~Existing Generating Unit~~	~~Installation of new excitation control system equipment.~~ ~~**AND**~~ ~~The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to a BES frequency excursion as specified in Criteria 1 above.~~	~~The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected~~
~~Existing Generating Unit~~	~~Subjected to an activity resulting in an alteration of the response of the turbine/governor and Load control or active power/frequency control model.~~ ~~**OR**~~ ~~Receive written comments including dated electronic or hard copy evidence indicating that the recorded turbine/governor and Load control or active power/frequency control response for three or more Transmission System event did not match the predicted control system model response..~~ ~~**OR**~~ ~~Receive written comments detailing technical concerns with the Generator Owner's turbine/governor and Load control or active power/frequency control model verification documentation.~~ ~~**AND**~~ ~~The Generator Owner has submitted a verification plan.~~ ~~**AND**~~ ~~The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to a BES frequency excursion as~~	~~The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected~~

	~~specified in Criteria 1 above.~~	
~~New or Existing Generator Unit~~	~~Excitation control system model identified as unusable by the Transmission Planner.~~ ~~**AND**~~ ~~The Generator Owner has submitted a verification plan.~~ ~~**AND**~~ ~~The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to a BES frequency excursion as specified in Criteria 1 above.~~	~~The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected~~
~~New Generating Unit~~	~~The first time the unit is operating in a control mode with MW output that would result in a turbine/governor and load control or active power/frequency control mode response (or the unit is subjected to a staged frequency reference change test if possible) and is subjected to aBES frequency excursion as specified in Criteria 1 above.~~	~~The recorded unit Real Power response for the frequency excursion shall be collected with the verified model and documentation transmitted to the Transmission Planner no more than 730 days from the date that the recorded response was collected~~

Event Triggering Verification	Verification Periodicity	Comments
Establishing the initial verification period (Criteria 2) for an applicable unit (Requirement R2)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1 on or after the Standard Implementation Effective Date. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test before or on the Standard Implementation Effective Date	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded. Criteria 4 applies when calculating generation fleet compliance during the 9-year transition period

Event Triggering Verification	Verification Periodicity	Comments
Subsequent verification for an existing applicable unit	Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit's ten year anniversary date of the collection of the recorded unit Real Power response used for the current validation. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test on or before the applicable unit's ten year anniversary date of the collection of the recorded unit Real Power response used for the current validation.	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed with settings final (Requirement R2)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1 OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the commissioning date	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
Existing applicable unit that is equivalent to another operating unit(s) at the same physical location AND Each equivalent applicable unit has the same MVA nameplate rating. AND	Verify a different equivalent unit during each ten year verification period.	Document circumstance with a written statement and include with the verified model and documentation and data provided to the Transmission Provider for the verified equivalent unit.

Event Triggering Verification	Verification Periodicity	Comments
The nameplate rating is ≤ 350 MVA. AND Each equivalent applicable unit has identical applicable components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)		Criteria 4 applies when calculating generation fleet compliance during the 9-year transition period.
Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period AND Neither an on-line speed governor reference test nor a partial load rejection test was performed. (Requirement R2)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1after the ten year verification period	Document circumstance with a written statement. Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
Existing applicable unit control system response is altered resulting in an alteration of the response of the turbine/governor and load control or active power/frequency control model AND The Generator Owner has submitted a verification plan. (Requirement R4)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan.	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
The Generator Owner receives written comments including dated electronic or hard copy evidence indicating that the recorded turbine/governor and load control or active power/frequency control response for three or more transmission system events did not match the predicted control system model	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the unit Real Power response was

Event Triggering Verification	Verification Periodicity	Comments
response. AND The Generator Owner has submitted a verification plan. (Requirement R3)	Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan	provided as part of the dated evidence.
The Generator Owner receives written comments detailing technical concerns with the Generator Owner's turbine/governor and load control and active power/frequency control model verification documentation. AND The Generator Owner has submitted a verification plan (Requirement R3)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.
The Turbine/governor and load control and active power/frequency control model identified as unusable by the Transmission Planner. AND The Generator Owner has submitted a verification plan. (Requirement R3)	Record unit Real Power response to the first frequency excursion event that meets Criteria 1. OR Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date that of the submitted verification plan	Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.

Event Triggering Verification	Verification Periodicity	Comments
New or existing applicable unit is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.) OR New or existing applicable unit has a disabled control system	Not required until responsive control mode operation for connected operations is established.	Document circumstance with a written statement. Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) once responsive control mode operation for connected operations is established.
New or existing applicable unit does not have an installed control system	Not required until unit has an installed control system	Document circumstance with a written statement. Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) once responsive control mode operation for connected operations is established.

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Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Transmission Planner

Generator Owner

For the purpose of this standard, the term "applicable Facility" is considered, "applicable units1." Units or plants with an average capacity2 factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system.

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1 Applicable generating units do not include startup or standby units not normally connected to the grid.

2 Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant or generating Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
    - Each individual generating unit greater than 20 MVA (gross nameplate rating); and
    - Each generating plant or generating Facility comprised of individual generating units less than 20 MVA (gross nameplate ratings)

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 25 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, three years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following applicable regulatory approval.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 25 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, three years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

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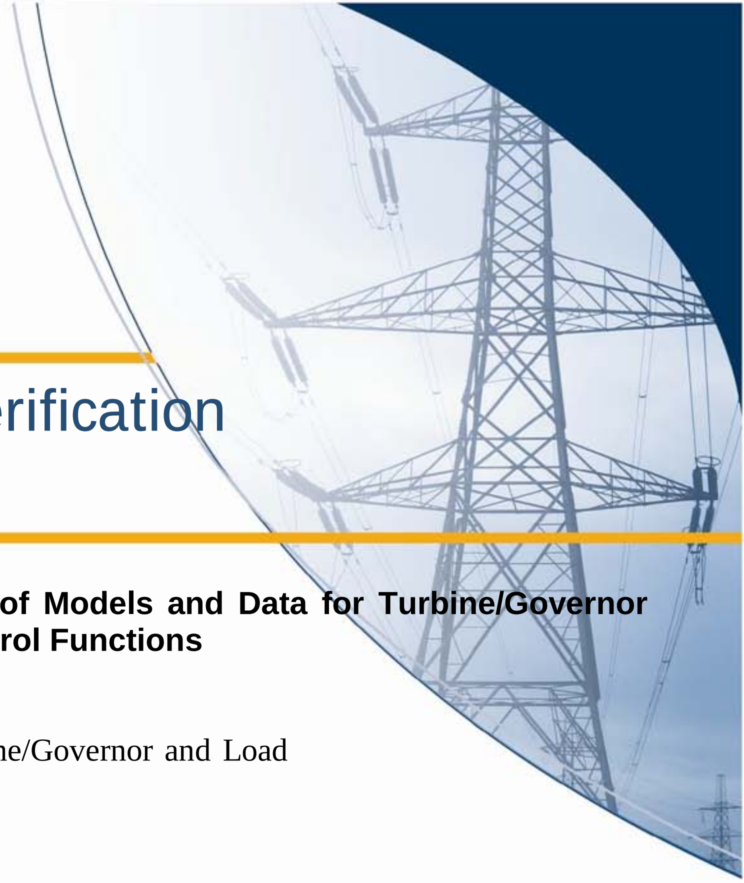

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Requested

MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of MOD-027-1:

- Transmission Planner
- Generator Owner
- Facilities

For the purpose of this standard, the following Facilities are considered, "applicable units.[1]" Units or plants with an average capacity[2] factor greater than 5% over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following:

[1] Applicable generating units do not include startup or standby units not normally connected to the grid.

[2] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

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- Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:
- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating):
  - o Each individual generating unit greater than 20 MVA (gross nameplate rating); and
  - o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - o Each individual generating unit greater than 20 MVA (gross nameplate rating); and
  - o Each generating plant or generating Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the bulk power system.
- For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - o Each individual generating unit greater than 20 MVA (gross nameplate rating); and
  - o Each generating plant or generating Facility comprised of individual generating units less than 20 MVA (gross nameplate ratings)

~~Each generating unit with a gross nameplate rating greater than or equal to 100 MVA, connected at the point of interconnection [3] at greater than or equal to 100 kV.~~

~~For each plant with a gross aggregate nameplate rating greater than or equal to 100 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:~~

~~Each unit with a gross nameplate rating greater than or equal to 20 MVA; and~~

~~The remainder of the plant as an aggregate.~~

~~Generating units connected to the Western Interconnection with the following characteristics:~~

~~Each generating unit with a gross nameplate rating greater than or equal to 75 MVA, connected at the point of interconnection3[2] at greater than or equal to 100 kV.~~

~~For each plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with at greater than or equal to 100 kV:~~

~~Each unit with a gross nameplate greater than or equal to 20 MVA; and~~

~~The remainder of the plant as an aggregate.~~

~~Generating units connected to the ERCOT Interconnection with the following characteristics:~~

~~Each generating unit with a gross nameplate rating of greater than or equal to 50 MVA, connected at the point of interconnection3[2] with rating greater than or equal to 100 kV.~~

~~For each plant with a gross aggregate nameplate rating of greater than or equal to 75 MVA, connected at the same point of interconnection at greater than or equal to 100 kV:~~

~~Each unit with a gross nameplate greater than or equal to 20 MVA; and~~

~~The remainder of the plant as an aggregate.~~

Effective Date

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 25 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the

[3] ~~The common transmission bus voltage level (i.e. 100 kV or greater) at which the generator step up transformer is connected.~~

first day of the first calendar quarter, three years following applicable regulatory approval.

- Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following applicable regulatory approval.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter, three years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 25 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, three years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following Board of Trustees adoption.

~~In those jurisdictions where regulatory approval is required:~~

~~By the first day of the first calendar quarter, three years following applicable regulatory approval:~~

- ~~At least 25% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.~~
- ~~100% compliant with Requirements R1, and R3 through R5.~~

~~By the first day of the first calendar quarter, five years following applicable regulatory approval:~~

- ~~At least 50% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.~~

~~By the first day of the first calendar quarter, seven years following applicable regulatory approval:~~

- ~~At least 75% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.~~

~~By the first day of the first calendar quarter, nine years following applicable regulatory approval:~~

- ~~100% of each Generator Owner's applicable units compliant with Requirement R2.~~

~~In those jurisdictions where no regulatory approval is required:~~

~~By the first day of the first calendar quarter, three years following Board of Trustees adoption:~~

- ~~At least 25% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.~~
- ~~100% compliant with Requirements R1, and R3 through R5.~~

~~By the first day of the first calendar quarter, five years following Board of Trustees adoption:~~

- ~~At least 50% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.~~

~~By the first day of the first calendar quarter, seven years following Board of Trustees adoption:~~

- ~~At least 75% of each Generator Owner's applicable units per Interconnection on an MVA basis compliant with Requirement R2.~~

~~By the first day of the first calendar quarter, nine years following Board of Trustees adoption:~~

- ~~100% of each Generator Owner's applicable units compliant with Requirement R2.~~

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011

Proposed Action Plan and Description of Current Draft:

This is the second draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and initial ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop second version draft standard.	July 2011 – February 2012
2. Post response to comments and conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.	February - March 2012
3. Develop responses to ballot comments.	March - June 2012
4. Post response to comments and conduct successive ballot.	June 2012
5. Develop responses to ballot comments.	June – July 2012
6. Post responses to comments and conduct recirculation ballot.	August 2012
7. BOT adoption.	September 2012
8. File with regulatory authorities.	November 2012

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-1

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.

4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.

4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 Any generator, regardless of size, that is a Blackstart Resource material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.

5.1.2 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.1.3 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.5 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

B. Requirements

R1. Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including In-service [1] limiters and protection functions) with the applicable Facility capabilities and Protection System settings. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. This coordination requires the following steps:

1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment assuming normal AVR control loop and system steady state operating conditions.

1.1.2. Check the settings determined in Part 1.1.1 are applied to the in-service equipment.

R2. Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*:

---

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

- Voltage regulating equipment changes
- Protection System settings or component changes
- Generating or synchronous condenser equipment capability changes, or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner will have evidence, such as example evidence provided in PRC-019 Section G, to show that its applicable Facility voltage regulating system controls and Protection System functions are coordinated with the applicable Facility capabilities and Protection System settings as specified in Requirement R1. As applicable, this may include the following:

- In service excitation system and voltage regulating system control, limiters and protection functions
- In-service generator or synchronous condenser protection system settings
- Generator or synchronous condenser capabilities, or
- Steady state stability limit.

The coordination should include 1) verifying the in-service limiters are set to operate before the protection and the protection is set to operate before conditions cause damage to equipment assuming normal AVR control loop and system steady state operating conditions, and 2) verifying the desired settings are applied to the in-service equipment.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination review required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 are met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Owner and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1.
R2	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days	The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 within 121 calendar days following the identification or

	following the identification or implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years but less than or equal to 5 years and 4 months.	following the identification or implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years and 4 months but less than or equal to 5 years and 8 months.	following the identification or implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years and 8 months but less than or equal to 6 years.	implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

Reimert, Donald, Protective Relaying For Power Generation Systems, Boca Raton, FL, Taylor & Francis, 2006

Version History

Version	Date	Action	Change Tracking

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of :

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or

- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.
- Converter over-temperature limiter and associated protection function.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

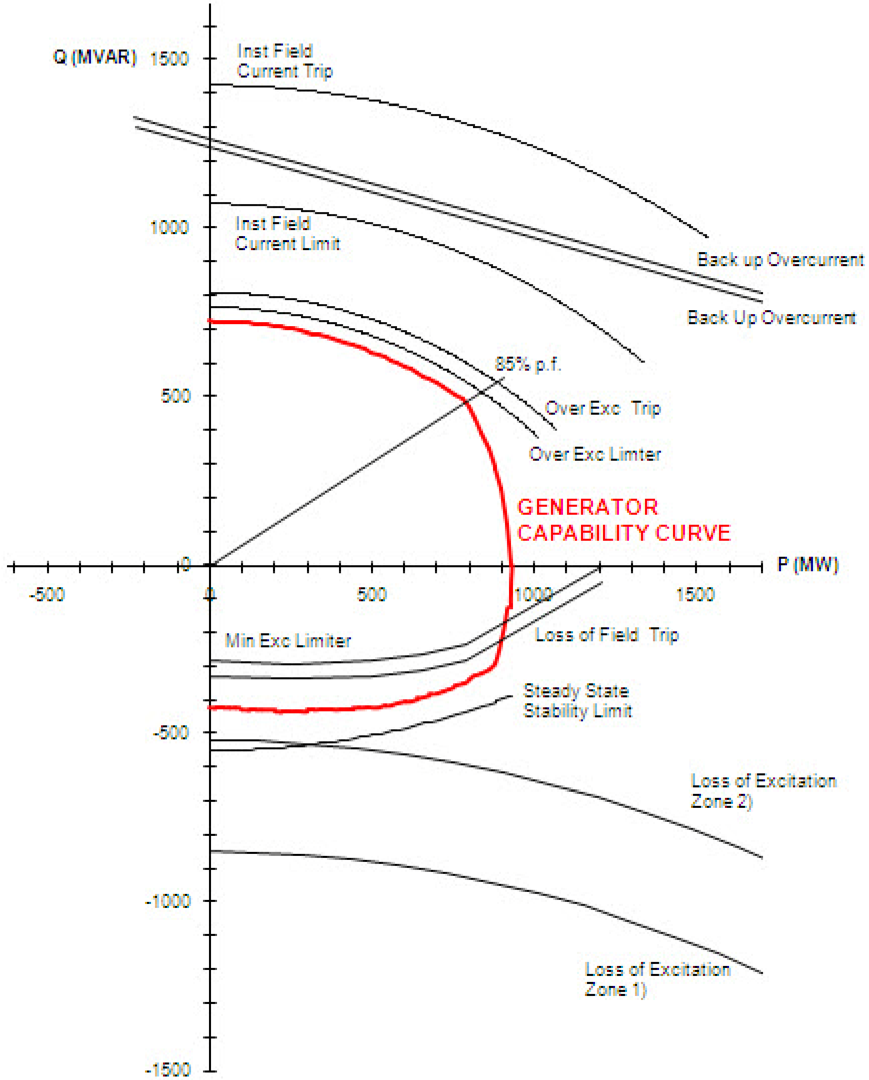
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

$$C = (X_d - X_s)/2$$

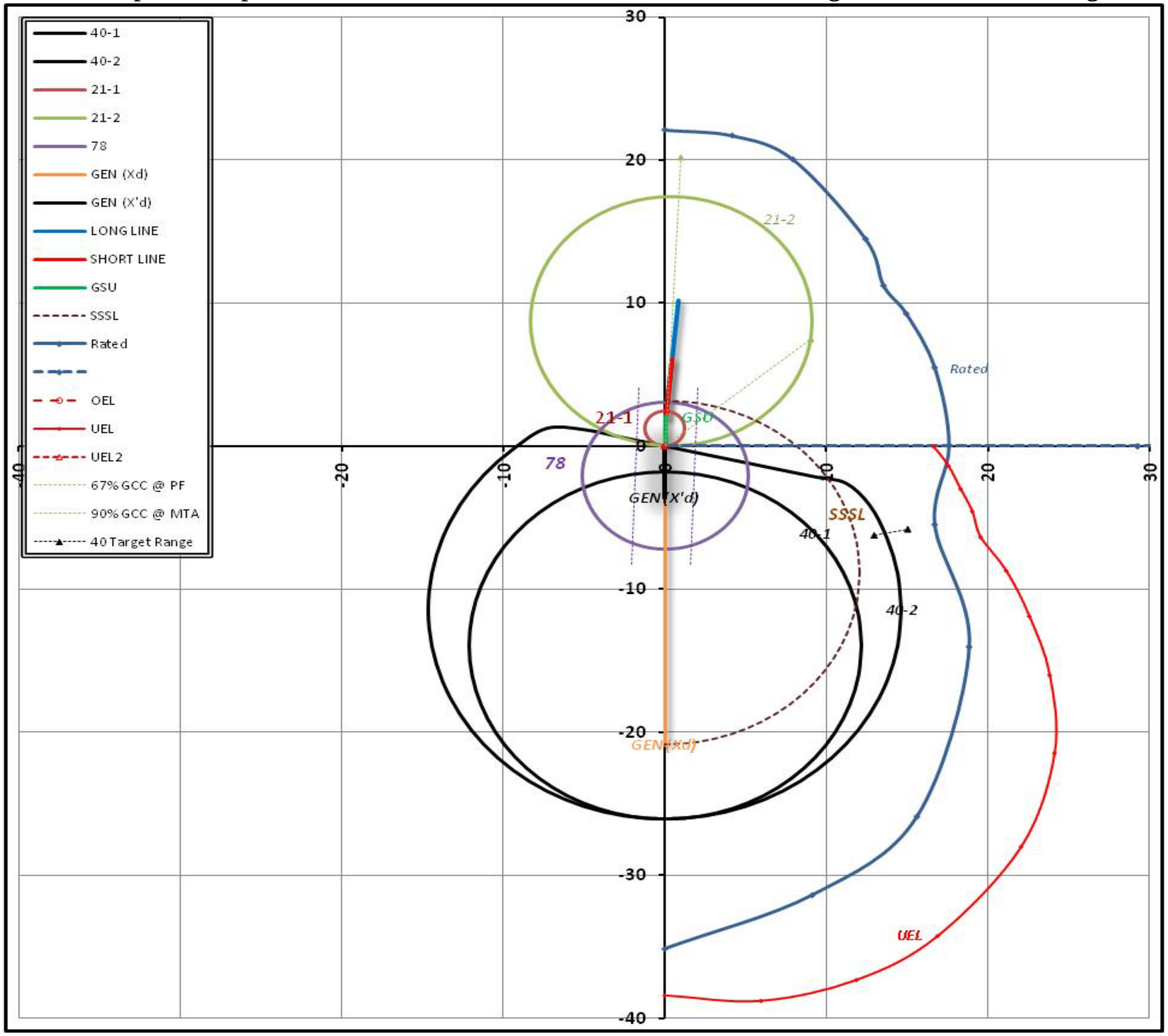
$$R = (X_d + X_s)/2$$

Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency

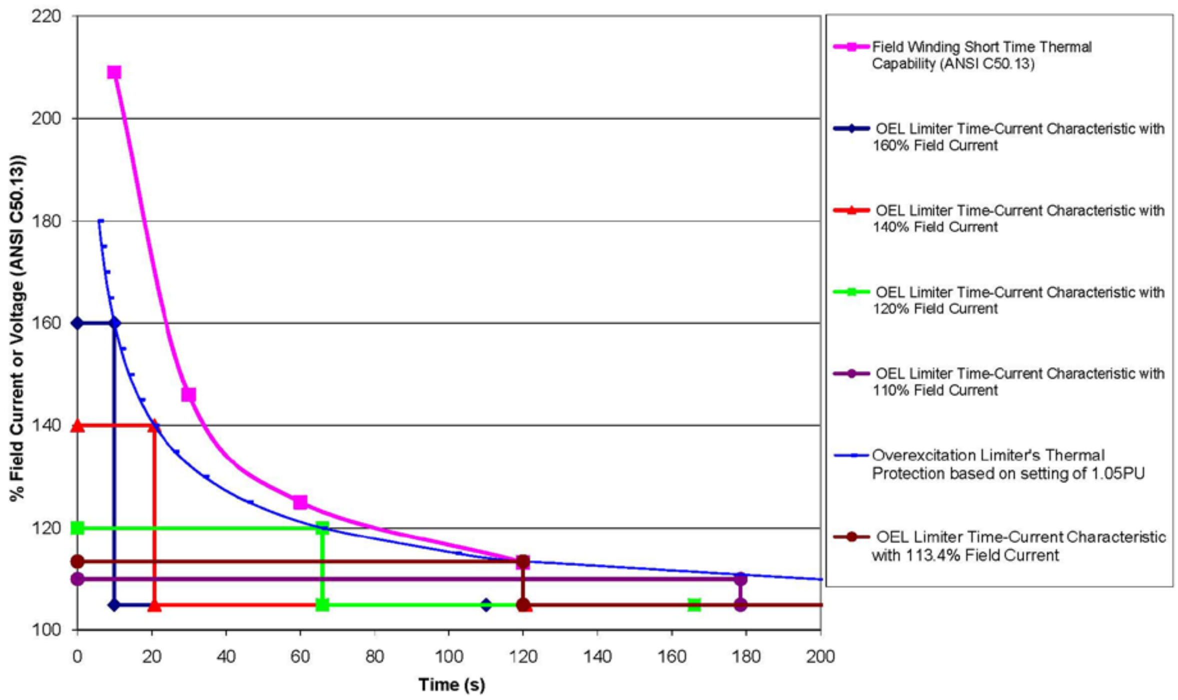


Example of Generator Capability Curve with Protection Elements Visible

Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011

Proposed Action Plan and Description of Current Draft:

This is the ~~first~~second draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a ~~30~~45-day concurrent formal comment period and initial ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. ~~Post first~~Develop responses to comments and develop second version draft ~~revision of~~ standard.	~~April-May~~July 2011 – February 2012
2. Post response to comments and ~~second version draft revision of~~conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.	~~July – August 2011~~February - March 2012
3. ~~Post response to comments and request authorization~~Develop responses to ballot ~~the revised standard~~comments.	~~September - October 2011~~March - June 2012
4. ~~Conduct initial~~Post response to comments and conduct successive ballot.	~~November 2011~~June 2012
5. ~~Post response~~Develop responses to ballot comments.	~~December 2011~~June – July 2012
6. ~~Conduct~~Post responses to comments and conduct recirculation ballot.	~~January~~August 2012
7. BOT adoption.	~~February~~September 2012
8. File with regulatory authorities.	~~March~~November 2012

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls ~~with Generating Unit or Plant Capabilities~~, and Protection

2. **Number:** PRC-019-1

3. **Purpose:** To ~~improve the reliability of the Bulk Electric System by preventing tripping of generating units and generating Facilities due to mis-~~verify coordination of generating unit ~~and generating~~ Facility or synchronous condenser voltage regulating controls ~~and~~, limit functions ~~with generator~~, equipment capabilities and ~~protection system~~ Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit ~~or synchronous condenser >~~greater than 20 MVA (gross nameplate rating) directly connected ~~at the point of interconnection at 100 kV or above~~to the bulk power system.

~~4.2.1~~4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.

~~4.2.2~~4.2.3 Generating plant ~~and generating Facility >~~/ Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating~~) connected at the point of interconnection at 100 kV or above.~~).

~~4.2.3~~4.2.4 ~~Blackstart Resources~~Any generator, regardless of size ~~included in~~, that is a Blackstart Resource material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20~~%~~ percent of its applicable ~~units~~Facilities.

5.1.2 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40~~%~~ percent of its applicable ~~units~~Facilities.

5.1.3 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60~~%~~ percent of its applicable ~~units~~Facilities.

5.1.4 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80~~%~~ percent of its applicable ~~units~~Facilities.

5.1.5 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100~~%~~ percent of its applicable ~~units~~Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20~~%~~ percent of its applicable ~~units~~Facilities.

5.2.2 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40~~%~~ percent of its applicable ~~units~~Facilities.

5.2.3 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60~~%~~ percent of its applicable ~~units~~Facilities.

5.2.4 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80~~%~~ percent of its applicable ~~units~~Facilities.

5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

B. Requirements

R1. Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate ~~its generating unit and generating Facility~~ the voltage regulating system controls, (including In-service [1] limiters and protection functions) with the ~~generating unit and~~applicable Facility ~~or synchronous condenser~~ capabilities and ~~protective system~~Protection System settings~~; to include as applicable:~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

- ~~In-service~~ [2] ~~excitation system and voltage regulating system control, limiters and protection functions~~
- ~~In-service generator or synchronous condenser protection system settings~~

- ~~Generating equipment or synchronous condenser capabilities~~
- ~~Steady state stability limit~~

1.1. This coordination requires the following steps:

1.1.1. Verify ~~that~~ the limiters are set to operate before the ~~protection~~Protection System and the ~~protection~~Protection System is set to operate before conditions ~~exceed~~cause damage to equipment ~~capabilities (including the steady state stability limit)~~ assuming normal AVR control loop and system steady state operating conditions.

1.1.2. Check ~~that~~ the settings determined in ~~Step~~Part 1.1.1 are applied to the in-service equipment.

~~M1.1~~R2. Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*:

- Voltage regulating equipment changes
- Protection ~~system~~System settings or component changes
- Generating or synchronous condenser equipment capability changes, or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner will have evidence, such as example ~~plots~~evidence provided in PRC-019 Section G, to show that its ~~generating unit and generating~~applicable Facility ~~or synchronous condenser excitation system and~~ voltage regulating system controls and ~~protection~~Protection System functions are coordinated with the ~~generating unit and generating~~applicable Facility capabilities and ~~protective system~~Protection System settings ~~applied to in-service equipment~~ as specified in Requirement R1. As applicable, this may include the following:

- In service excitation system and voltage regulating system control, limiters and protection functions
- In-service generator or synchronous condenser protection system settings
- ~~, Section 1.1, and one previous dated set of evidence that demonstrates the latest~~Generator or synchronous condenser capabilities, or

[2] ~~Limiters or protective functions that are installed and activated on the generator or synchronous condenser.~~

- Steady state stability limit.

The coordination ~~review has been done within~~should include 1) verifying the ~~intervals specified in Requirement R1, Section 1.2. If~~in-service limiters are set to operate before the ~~latest coordination review is performed due~~protection and the protection is set to ~~a change in the~~ operate before conditions cause damage to equipment assuming normal AVR control loop and system steady state operating conditions, and 2) verifying the desired settings are applied to the in-service equipment ~~or settings that changes the coordination, the~~ .

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence ~~(such as a work order) that demonstrates when~~ of the ~~change was implemented~~coordination review required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 are met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. ~~Data~~Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Owner and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner and Transmission Owner shall retain ~~the latest and the prior~~ evidence of compliance with ~~Requirement~~Requirements R1~~,~~ ~~Measure~~ and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance ~~Violation~~ Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1.
~~R1~~R2	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years but less than or equal to 5 years and 4	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years and 4 months but less than or equal to 5	The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years and 8 months but less than or equal to 6	The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 ~~at least once every five years.~~ within 121 calendar days following the identification or implementation of a change that affected the coordination. OR The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 ~~within 121 calendar days following the~~

	months.	years and 8 months.	years.	~~identification or implementation of a change that affected the coordination.~~ in more than 6 years.

E. **Regional Variances**

None.

F. **Associated Documents**

~~None.~~

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

Reimert, Donald, Protective Relaying For Power Generation Systems, Boca Raton, FL, Taylor & Francis, 2006

Version History

Version	Date	Action	Change Tracking

G. **Reference**

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of ~~one or more plots including (but not limited to):~~:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- ~~These plots contain~~Equivalent tables or other evidence

This evidence should include the equipment capabilities~~,~~ and the operating region for the limiters and protection ~~function such as; under-excitation limiters, steady state stability limits, or loss of field protection curves. Additional limiters and protection function that are installed and in-service can be incorporated as an Inverse Time Limit/Protection~~

~~Characteristic Plot (Attachment 3) or into the Generator Reactive Capability Curve Plot or an R-X diagram plot, identified above.~~functions

Equipment limits, types of limiters and protection functions which could be coordinated include~~:~~ (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.
- Converter over-temperature limiter and associated protection function.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

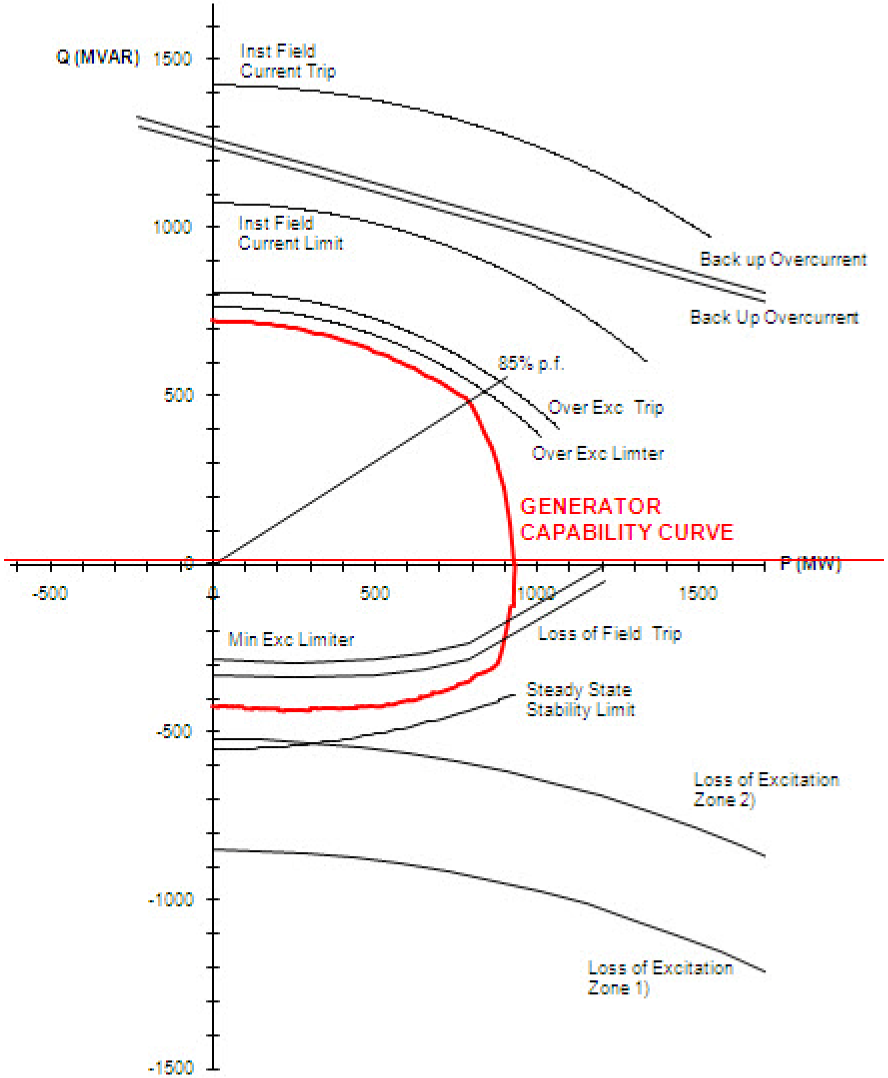
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

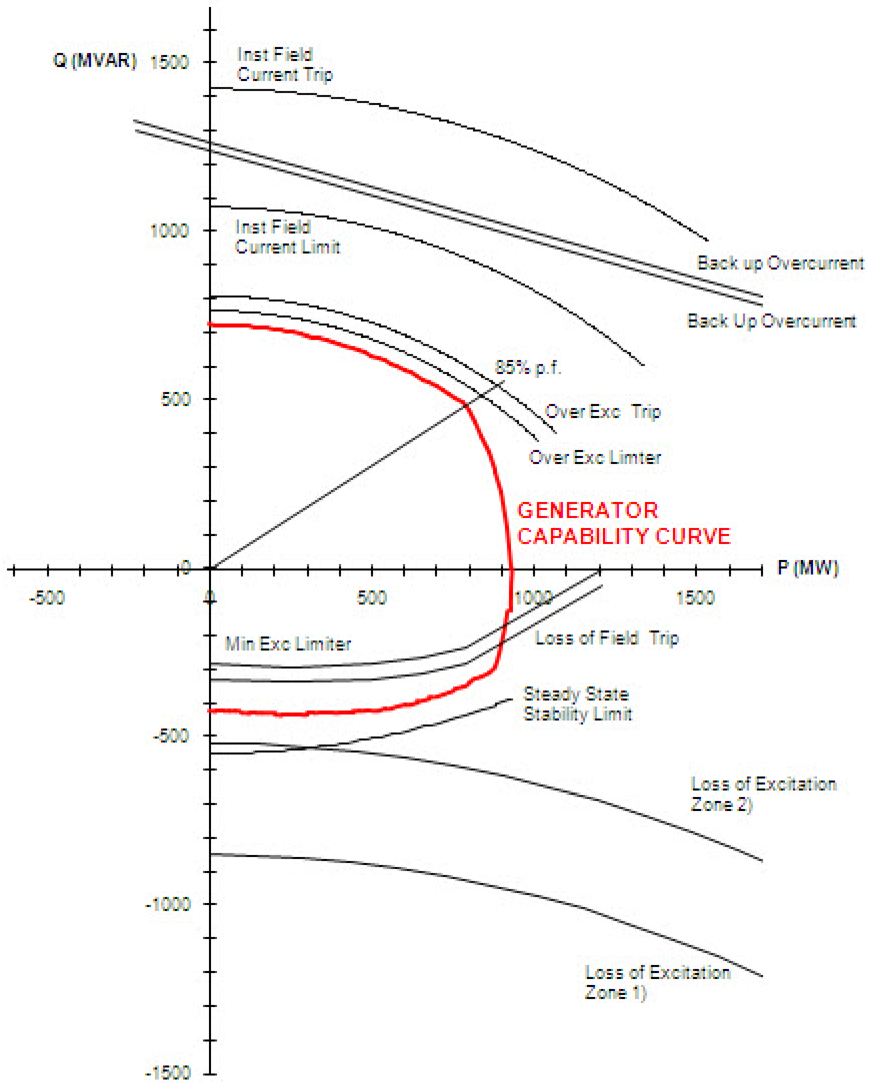
$C = (X_d - X_s)/2$

$R = (X_d + X_s)/2$

Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency

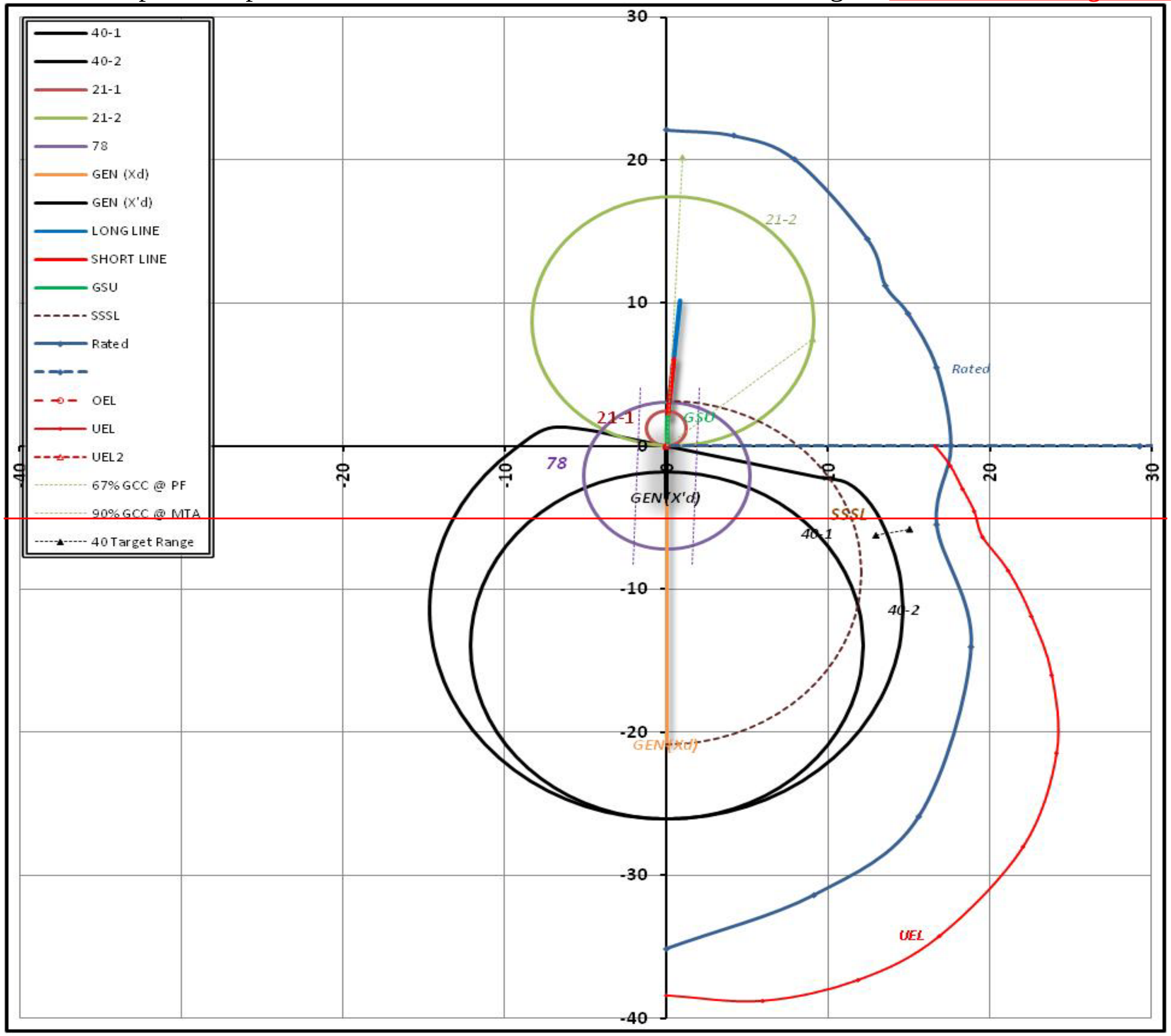


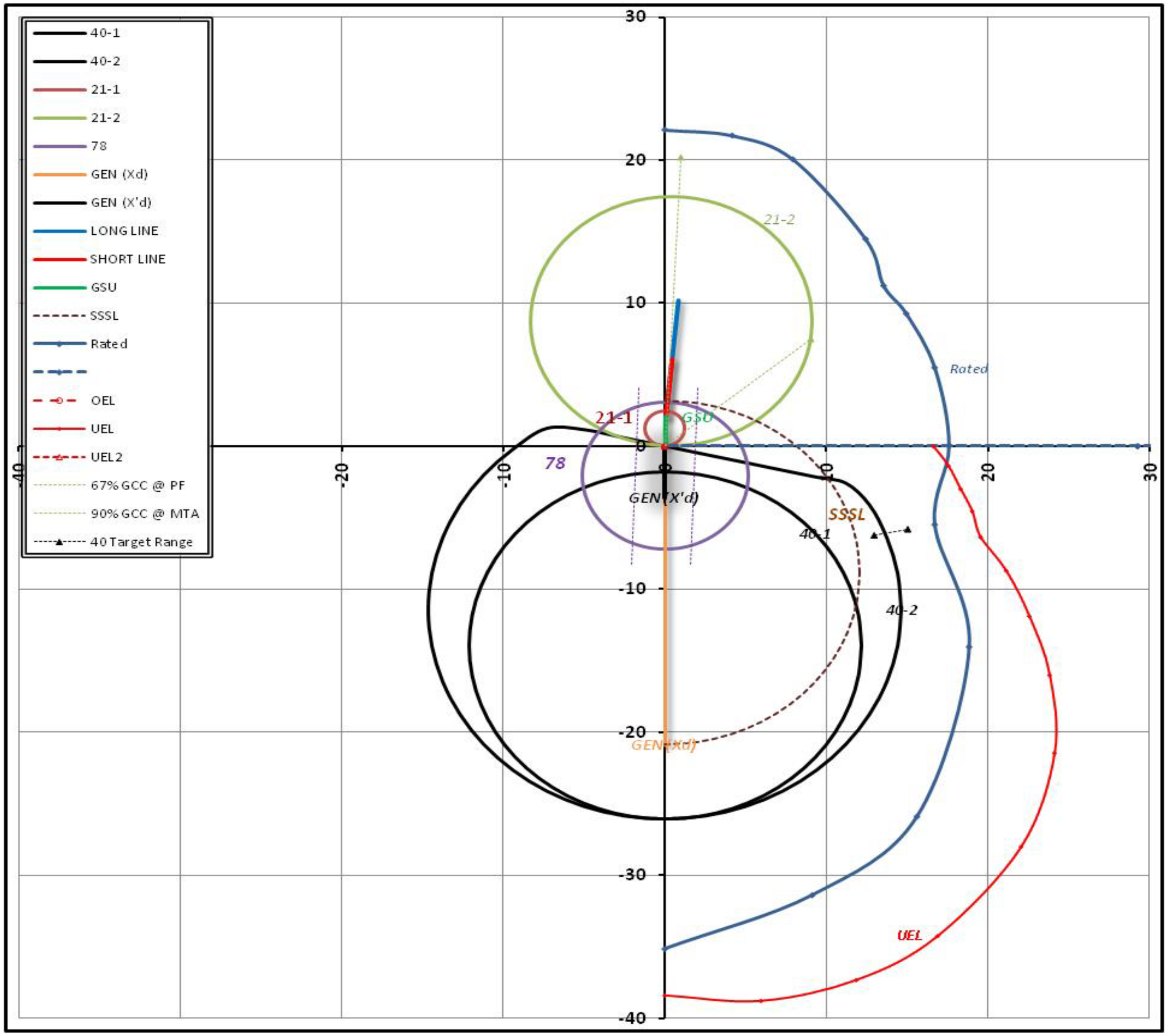
Example of Generator Capability Curve with Protection Elements Visible



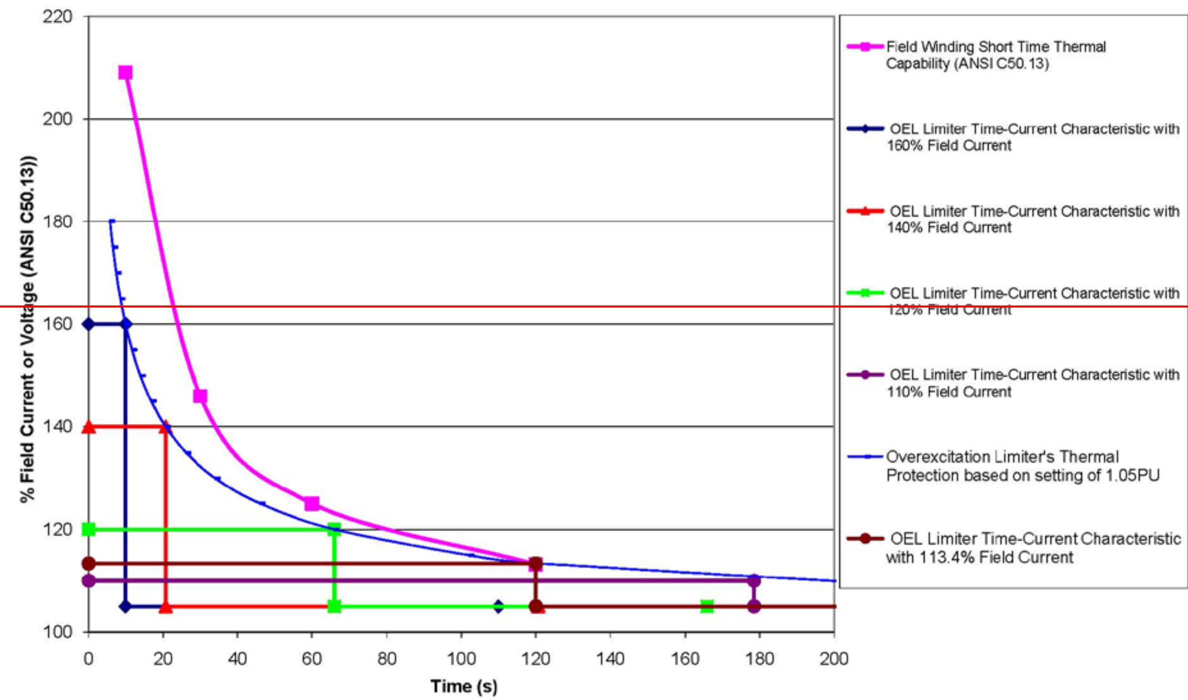
Example of Generator Capability Curve with Protection Elements Visible

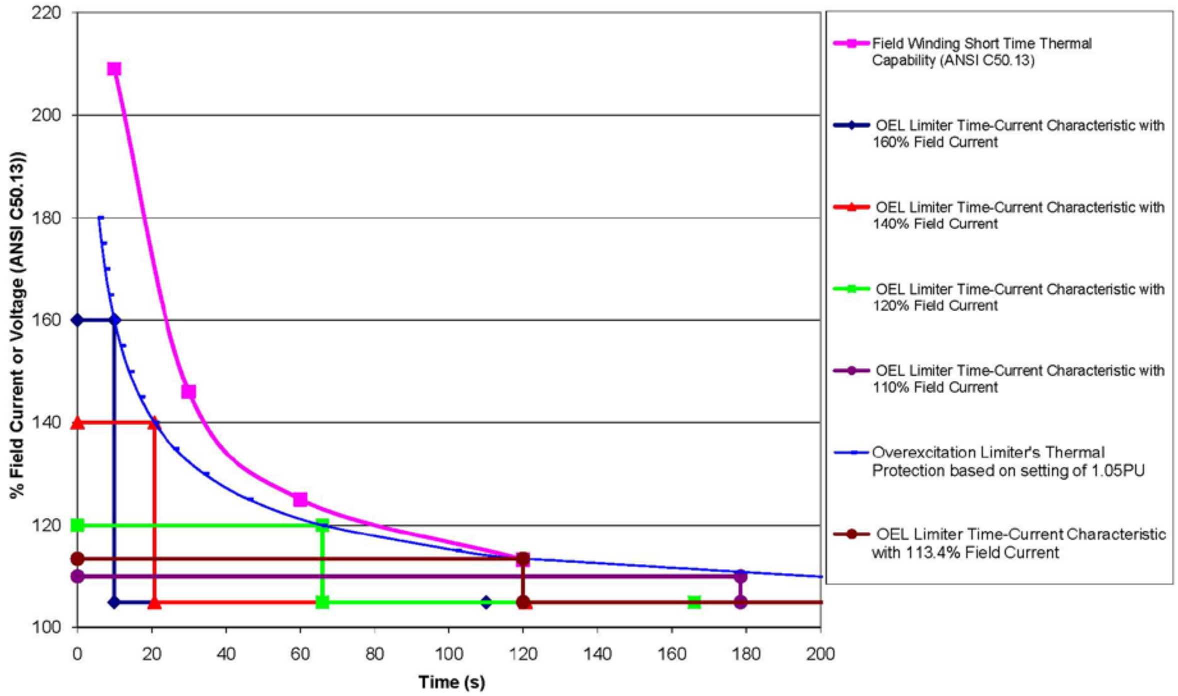
Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency




40-1
40-2
21-1
21-2
78
GEN (Xd)
GEN (X'd)
LONG LINE
SHORT LINE
GSU
SSSL
Rated
OEL
UEL
UEL2
67% GCC @ PF
90% GCC @ MTA
40 Target Range
30
20
10
0
-10
-20
-30
-40
21-2
Rated
21-1
GSU
78
GEN (X'd)
SSSL
40-1
40-2
GEN (Xd)
UEL

Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot




220
200
180
160
140
120
100
% Field Current or Voltage (ANSI C50.13))
0
20
40
60
80
100
120
140
160
180
200
Time (s)
Field Winding Short Time Thermal Capability (ANSI C50.13)
OEL Limiter Time-Current Characteristic with 160% Field Current
OEL Limiter Time-Current Characteristic with 140% Field Current
OEL Limiter Time-Current Characteristic with 120% Field Current
OEL Limiter Time-Current Characteristic with 110% Field Current
Overexcitation Limiter's Thermal Protection based on setting of 1.05PU
OEL Limiter Time-Current Characteristic with 113.4% Field Current

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Approvals Required

PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner that owns synchronous condenser(s)

Applicable Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.
- Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system.
- Generating plant/Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).
- Any generator, regardless of size, that is a Blackstart Resource material to and designated as part of a Transmission Operator's restoration plan.

Conforming Changes to Other Standards
None

Effective Dates
PRC-019-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, one calendar year following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.
- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.
- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, one calendar year following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.
- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Justification for Phasing:

The coordination activities in this standard (PRC-019-1) are most effectively performed just prior to the performance of a reactive capability test, as required by MOD-025-2. Hence, the SDT has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2.

Retirements

None

Project 2007-09 Generator Verification Implementation Plan

Implementation Plan for PRC-019-1, Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls ~~with Generating Unit or Plant Capabilities~~ and Protection

Approvals Requested:

PRC-019-1 - Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls ~~with Generating Unit or Plant Capabilities~~ and Protection

Prerequisite Approvals

None

Revisions to Approved Standards and Definitions

None

Compliance with the Standard

The following entities are responsible for being compliant with all requirements of PRC-019-1:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

- Facilities:
  - Individual generating unit ~~and synchronous condenser >~~ greater than 20 MVA (gross nameplate rating) in a generating Facility directly connected to the bulk power system~~at the point of interconnection at 100 kV or above~~.
  - Individual synchronous condenser greater than 20 MVA (gross nameplate rating) in a generating Facility directly connected to the bulk power system
  - Generating plant/Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than~~>~~ 75 MVA (gross aggregate nameplate rating)~~ and connected at the point of interconnection at 100 kV or above~~.
  - ~~Blackstart units~~Any generator, regardless of size, that is a Blackstart Resource material to and designated as part of~~ included in~~ a Transmission Operator's restoration ~~Blackstart Capability P~~plan.

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Princeton, NJ 08540
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Effective Date

The first day of the first calendar quarter ~~tw~~one years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter ~~tw~~one years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 20~~%~~ percent of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter two years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two~~hree~~ years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 40 percent~~%~~ of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter three years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 60 percent~~%~~ of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter four years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter four years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have at least 80 percent~~%~~ of applicable units and facilities fully compliant with this standard.

The first day of the first calendar quarter five years following applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter five years following Board of Trustees adoption:

- Each Generator Owner and Transmission Owner shall have 100 percent~~%~~ of applicable units and facilities fully compliant with this standard.

Justification for Phasing:

The coordination activities in this standard (PRC-019-1) are most effectively performed just prior to the performance of a reactive capability test as required by MOD-025-2. Hence, the SDT has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2.

Retirements

None

Unofficial Comment Form

Project 2007-09 Generator Verification

MOD-025-2, MOD-027-1 and PRC-019-1

Please **DO NOT** use this form to submit comments. Please use the electronic comment form to submit comments on the proposed revisions to MOD-025-2, MOD-027-1 and PRC-019-1. Comments must be submitted by **April 16, 2012.** If you have questions please contact Stephen Crutchfield at Stephen.Crutchfield@nerc.net or by telephone at (609) 651-9455.

Background Information:

The GVSDT posted the draft standards June 15 – July 15, 2011 for a formal comment period. Based on stakeholder feedback, the GVSDT made revisions to the standards. A number of commenters suggested revisions for clarity that were accepted by the GVSDT. Minor changes were made to the standard to incorporate those suggestions.

MOD-025-2

Language was added to recommend that the AVR be in automatic control while conducting reactive capability testing, but that reactive capability testing must be done even if the AVR is not available. The following language was also added to allow flexibility if 90 percent of the generation is not available when testing wind turbines or photovoltaic inverters:

> "If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold."

When polled, most stakeholders agree with combining MOD-024-1 and MOD-025-2 into a single standard. Several commenters suggested that the standard be clarified to indicate that Real and Reactive Power testing may be performed under separate tests. The GVSDT agrees and has separated R1 into two requirements to allow for separate Real and Reactive Power testing. The intent of these requirements remains unchanged. Requirement R1 now deals with Real Power testing only, while Requirement R2 deals with Reactive Power testing. The measure and VSL for R1 were also revised to match the requirements.

> R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Verify the Reactive Power capability of its generating units, and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

A statement was also added to the beginning of Attachment 1 for additional clarity:

> "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard."

There was an error in the question relating to the Transmission Owner on the previous comment form. The question should have asked if the Transmission Planner was the appropriate entity, rather than the Transmission Owner. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-2. The GVSDT is confirming this with an additional question on this topic in this posting.

With regard to correction factors for verifications, many commenters pointed out there are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The GVSDT has revised the standard to include any parameter that the Generator Owner determines is required to make the ambient correction in Attachment 1:

3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature

The standard gives the Transmission Planner the discretion to request ambient condition correction at time of verification.

There was overwhelming stakeholder support for verifying synchronous condensers as a reactive resource under MOD-025-2. Some stakeholders suggested that consideration be given under this or a different standard for verification of other reactive resources.

The SDT added the following sentence to Attachment 1 in response to a stakeholder comment for clarity:

> "If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes."

There was an error in the comment form for the question regarding synchronous condenser size. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. While some commenters suggested values higher than 20 MVA, technical justification was not provided for a value exceeding the generator registration criterion of 20 MVA. The GVSDT will confirm this with an additional question on this topic in the next posting.

Commenters have identified regional variances currently in effect as required by MOD-024 and MOD-025. It is anticipated that these regional standards will be retired once MOD-025-2 is approved. Language provided by Reliability*First* staff has been added to the implementation plan concerning the Reliability*First* standards:

> "It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements."

MOD-027-1

The GVSDT expanded the applicability of MOD-027-1 to include plants/facilities comprised of multiple small units, such as variable energy resource plants/facilities. Stakeholders were asked whether they were aware of other generation configurations or types that should be covered in the Applicability. The vast majority of industry agrees that all of generation configurations or types that should be included in the Applicability section are specified in the current draft of the standard. A few minority comments were received suggesting that the Applicability section proposed should either be expanded or reduced. The GVSDT believes industry supports the current draft of the proposed Applicability.

The GVSDT did not propose a requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and Load control and active power/frequency control system model for a unit not specified in the standard Applicability section. This was discussed in relation to the proposed MOD-026-1, where a Planning Coordinator may request excitation control system information for a technically justified unit. The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next. Stakeholders were asked if they agreed with this approach. The majority of industry comments support the GVSDT proposal not to include a requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. There is minority opinion suggesting that such a requirement should be developed; with some commenters also questioning the basis for the Applicability section and the capacity factor philosophy. Most of the minority comments were received from one reliability region and, as such, the GVSDT suggests that region should consider developing a regional standard containing a more stringent applicability. The Planning Coordinator can still request a model review; however, the review is not mandatory under the standard requirements.

Based on industry comments received, the following modifications to the proposed standard have been made by the GVSDT:

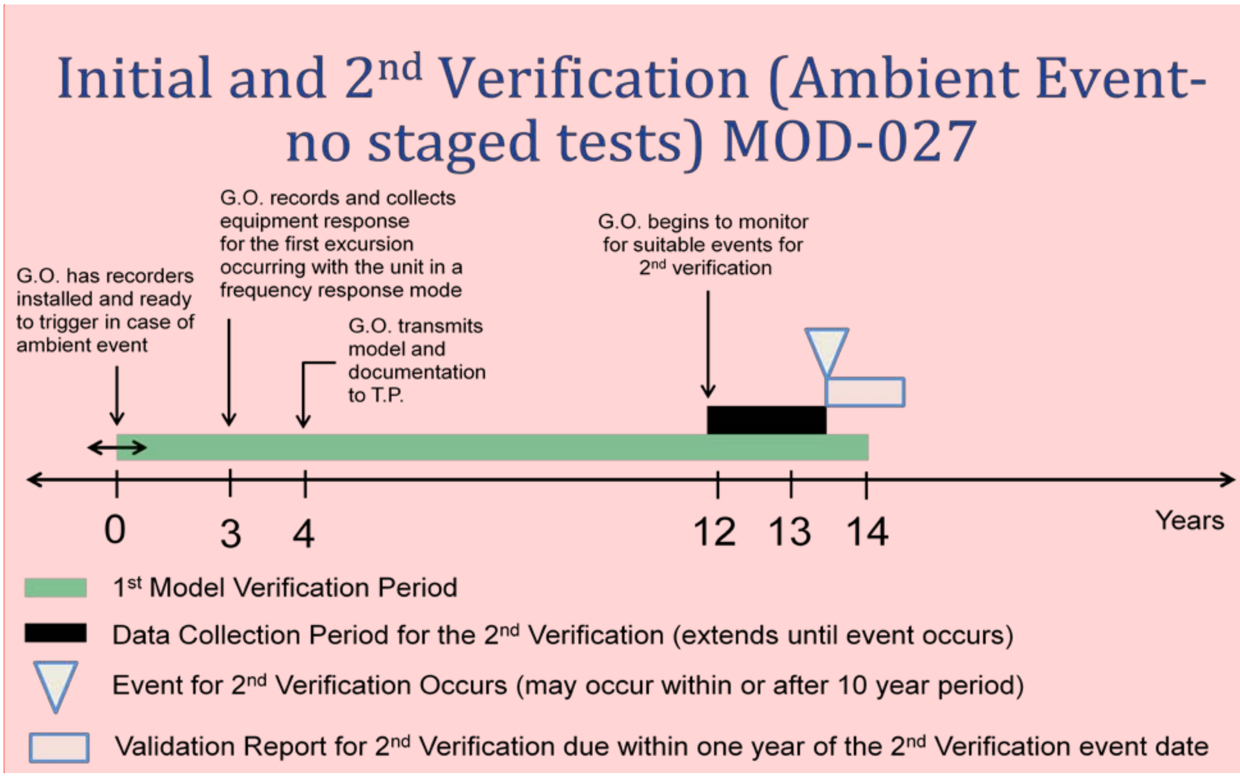
1) Corrections of various typos in the body of the standard, the VSLs, and in Attachment 1
2) Extended the time to comply with Requirement 1 from 30 to 90 days
3) Modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base-loaded unit is considered verified)
4) Modified Attachment 1 (Periodicity Table) to clarify establishing the Initial 10-Year Unit Verification Period Start Date
5) Reduced the maximum time allowed between capture of an event and completing model verification from two years to one year
6) Referenced the NERC GADS document for references to capacity factor in the draft standard
7) Included partial load rejection as a potential test to obtain a recording of the equipment response to be used in model verification

Periodicity Table (Attachment 1) for MOD-027-1:

Based on industry comments from the last posting, the GVSDT modified the Periodicity Table (Attachment 1) in an effort to convey the required periodicity of model verification in a simple but complete format. The following examples are offered by the GVSDT to aid industry in understanding the proposed model verification periodicity:

Periodicity Example 1:

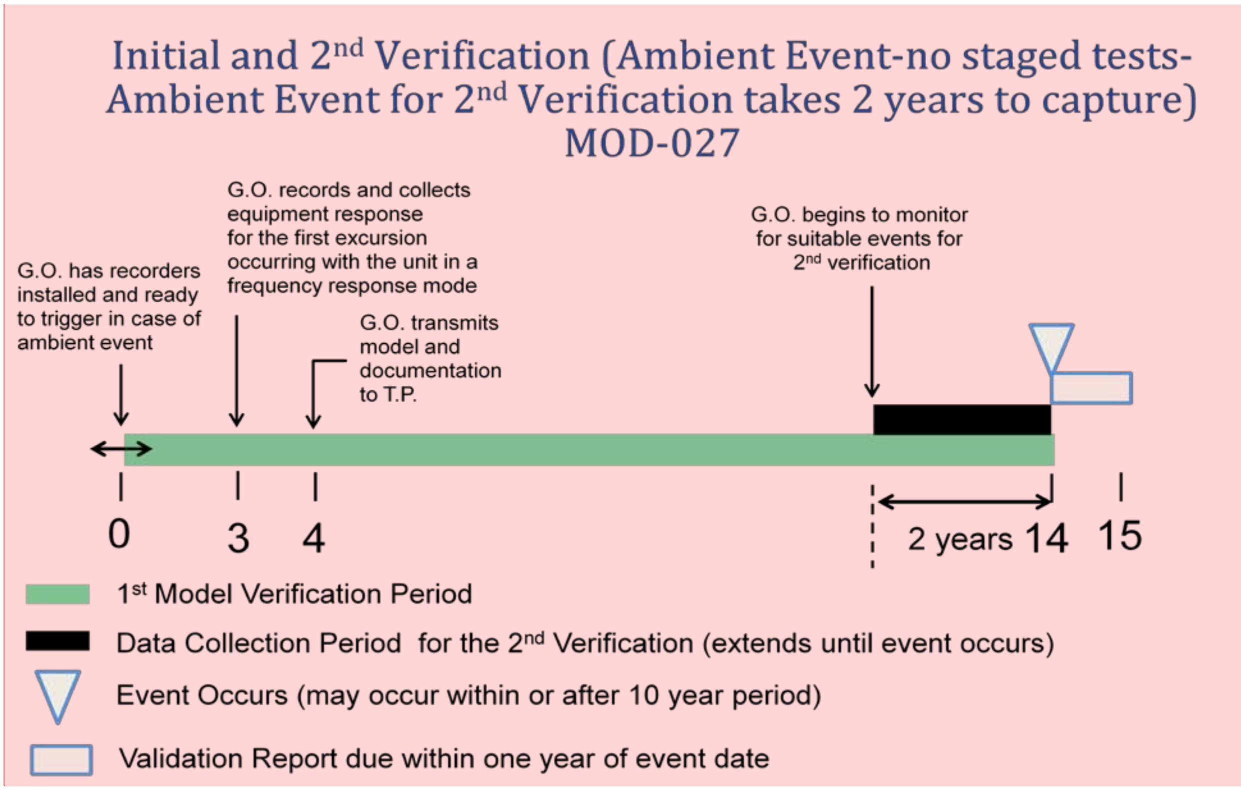
The following timeline depicts a scenario where the Generator Owner has recorders installed before its effective start date for R2 (3, 5, 7, or 9 years, shown as Year 0 in all four examples), and ready to capture the frequency response of the unit to an ambient event. The Generator Owner has decided to not perform a staged test. The first time the unit is operating in a frequency responsive mode and is subjected to a BES frequency excursion, as specified in Criteria 1, as specified in the Periodicity Table, the Generator Owner records the unit's Real Power response and then has one year to verify the model and transmit the model and documentation to the Transmission Planner. In this example, the first event with the unit in the proper operating mode occurred exactly at Year 3. Also, this example assumes that the Generator Owner took the entire year allowed to finish verifying and transmitting the model to the Transmission Planner exactly at Year 4. Once the model is initially verified, the expectation is that it will be verified again after a 10-year period. For this scenario, the requirements detailing activities by exception do not occur (R3 – R4), which is expected to be the situation for the majority of the time. Thus, per the Periodicity Table, the Generator Owner must begin to monitor for suitable ambient events for the second verification one year before the unit's 10-year anniversary date of the collection of the recorded unit response used for the current validation (Year 12). For this example, it is assumed that the event occurs sometime between Years 13 and 14; and from that point, the Generator Owner would have one year to complete the verification and transmit the model and documentation to the Transmission Planner.



[LA1]

Periodicity Example #2:

The second example is much like Example #1. The only difference is that for the second verification, two years passed before the first time the unit was operating in a frequency responsive mode and was subjected to a BES frequency excursion, as specified in Criteria 1, as specified in the Periodicity Table. This would also mean that for the third verification, active monitoring for an ambient event would need to begin at Year 23 (1 year before the 10-year anniversary of the collection of the previous event data used for verification):

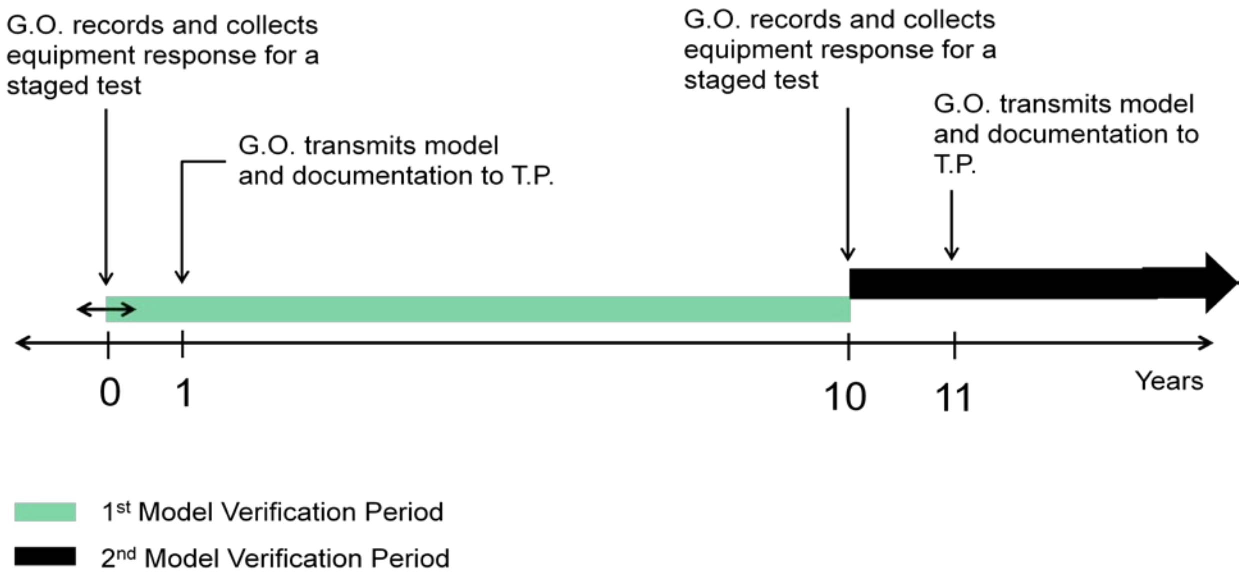


[LA2]

Periodicity Example #3:

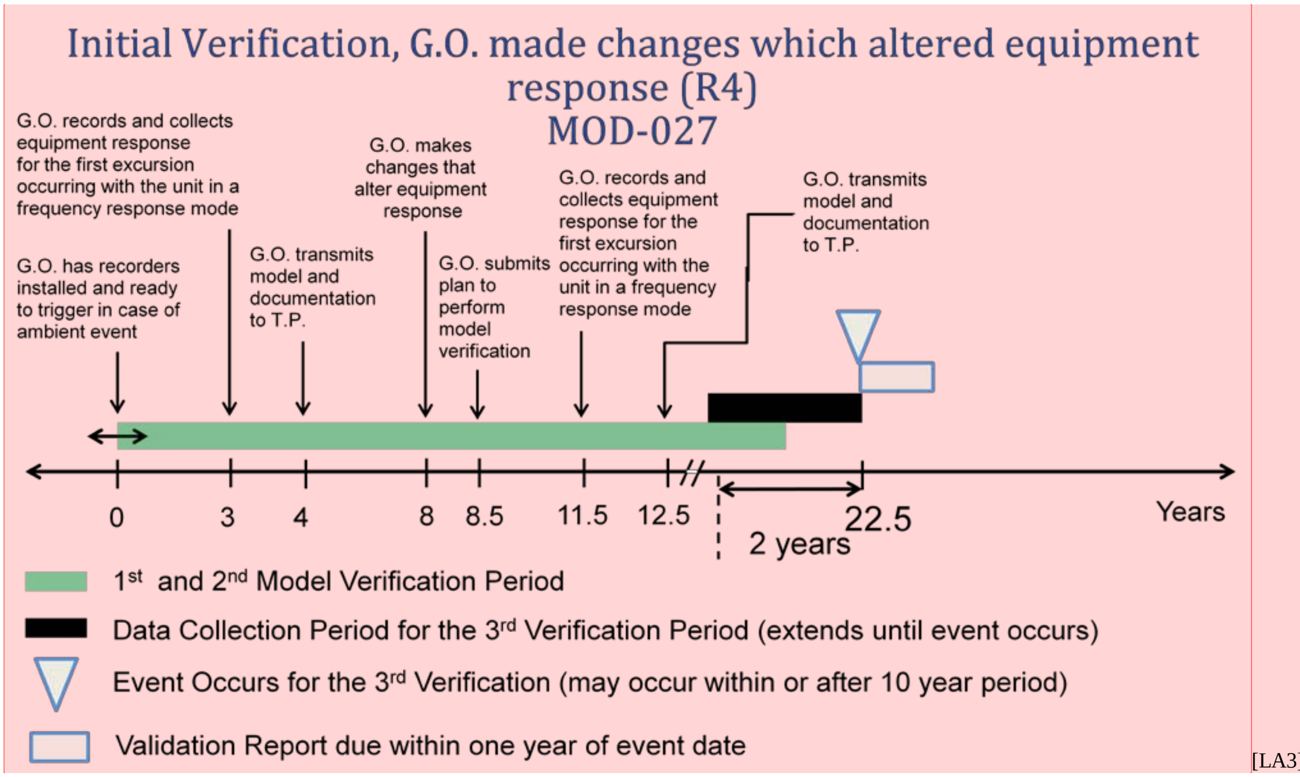
The third example assumes that the Generator Owner chooses to perform a staged test. For the first verification, the staged test has to be performed on or before the effective start date of R2 (3, 5, 7, or 9 years – shown as Year 0 on the timeline below). For simplicity of the example, the timeline shown assumes that the staged test for the first verification is performed exactly on the effective date. The requirements detailing activities by exception do not occur (R3 – R4); which is expected to be the situation for the majority of the time. For the second verification, another stage test is performed exactly on the Year 10 anniversary date of the initial staged test. Regarding the third verification (which is not shown on the following timeline), the GO would need to perform the staged test and collect the associated date on or before the unit's 10-year anniversary date of the staged test used for the current validation (i.e., response has to be collected on or before Year 20), and transmit the model and documentation to the Transmission Planner no later than 365 days later (i.e., by Year 21).

Initial and 2nd Verification (Staged tests) MOD-027



Periodicity Example #4:

The fourth example details a scenario in which the GVSDT anticipates would rarely occur. Initially, before Year 8, the Example #4 is identical to Example #1. However, the scenario assumes that eight years after the effective date of R2, the Generator Owner performs an activity which changes the equipment response. As detailed in Requirement 4, the Generator Owner has 180 days to determine if updated model data can be provided, or if the model needs to be re-verified. The example timeline below assumes that later; i.e., the Generator Owner submits a plan in 180 days to re-verify the model. From that point, per the Periodicity Table, the Generator Owner begins to monitor for an appropriate ambient event while the unit is in a mode that it is expected to govern. Once the ambient event has occurred, then the Generator Owner has an additional year to transmit the model and documentation to the Transmission Planner. In this example, the ambient event with the unit in the proper operating mode occurred in three years after the Generator Owner decided to verify the model (i.e., Year 11.5), and the Generator Owner completed model verification and transmitted the results to the Transmission Planner at Year 12.5. Therefore, for the next verification period, active monitoring for the next ambient event begins at Year 20.5 (one year before the 10-year anniversary date of the recorded event used for the current verification). The example timeline goes on to assume that an event was captured two years later (Year 22.5), verification completed with documentation submitted to the Transmission Planner one year later (Year 23.5).



[LA3]

PRC-019-1

The majority of stakeholders agreed with the proposed standard and provided some comments for revisions to the standard. The Applicability to Transmission Owners was clarified to include only those that own synchronous condenser(s) as follows:

4.1.2 Transmission Owner that owns synchronous condenser(s).

The GVSDT asked stakeholders if they believed that the proposed PRC-019-1 standard was written to be "technology neutral," such that it can be used for all forms of generation connected to the BES. The vast majority of stakeholders believe that the standard is technology neutral. Several stakeholders that expressed concerns commented that the standard may not work for photovoltaic or wind technologies. The GVSDT agrees that while some of the standard elements might not apply to all technologies, most elements in the example diagrams (in general) would apply to all technologies.

One stakeholder recognized that the SSSL calculation plot used in the example diagrams is based on a fixed-field current, which would require the excitation system to be in Manual Mode. The GVSDT, having previously considered this and knowing the excitation system to typically be in Auto Mode, per VAR-002, provided the following response: The calculation of the SSSL based on a fixed-field current value is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex.

The GVSDT asked stakeholders if they agreed with the applicability to synchronous condensers. The question contained a limit of ≥50 MVA, while the standard contained ≥20 MVA. The GVSDT intended for ≥20 MVA to be the correct number. Many stakeholders pointed out this discrepancy and agreed with the ≥20 MVA threshold. The GVSDT will ask this question again in this posting (see Question 1 below).

Some stakeholders suggested higher MVA limits for units applicable to this standard. The GVSDT based the applicability criteria on the current Compliance Registry Criteria and the current posted draft of the BES definition, both of which currently set the applicability threshold at 20 MVA for individual units. The SDT felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry Criteria and the BES definition.

Constellation Power pointed out that repeating the Compliance Registry Criteria within the standard is not wise since the standard must be changed if the Compliance Registry Criteria changes. The SDT agrees with this logic but felt it was necessary to include the appropriate Compliance Registry Criteria within the standard because the standard also applies to synchronous condensers, which are not explicitly mentioned in the Compliance Registry Criteria. If the Compliance Registry Criteria language for generating units was not included in the standard, the standard could be interpreted to apply only to synchronous condensers and not to generators.

Stakeholders were asked if they thought that variable static reactive sources that are not located at generating facilities should be included in the standard. The vast majority of stakeholders did not see a reliability need for including variable static reactive sources that are not located at generating facilities. This equipment is normally protected for internal failures and do not have similar equipment protection such as synchronous generators using generator field limiters and over- and under-excitation protection. The SDT has determined that variable static reactive resources not located at generating facilities are outside the scope of this project. For these reasons, including static reactive resources not located at a generating facility, are not part of this standard.

The majority of stakeholders agreed with the Purpose Statement of PRC-019-1. The GVSDT revised the Purpose Statement of the standard for clarity based on stakeholder comments. The revised Purpose Statement is:

> To improve the reliability of the Bulk Electric System by ensuring coordination of generating unit/facility or synchronous condenser voltage regulating controls and limit functions with generator capabilities and protection system settings.

The proposed effective dates provide a “phased-in” approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/facilities. The majority of stakeholders agreed with the phased-in approach. Stakeholders pointed out that, for jurisdictions where regulatory approval is not required, the 100% completion item was missing. The GVSDT added item 5.2.5:

> 5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees’ approval, each Generator Owner and Transmission Owner shall have verified 100% of its applicable units.

Stakeholders were asked about Section G of the standard which provides examples of how the coordination can be demonstrated. The majority of stakeholders agreed with the information provided, and several stakeholders made suggestion for clarifying language. Specific changes were made to Section G of the standard based on comments received. These changes included:

1. The example diagrams added that they are drawn at nominal voltage and frequency.
2. The formula for calculating the radius of the SSSL was corrected.
3. The items “under-excited limiters or minimum excitation limiters” and “over-excited limiters or maximum excitation limiters” have been placed in the bulleted list of the standard.
4. The SDT changed “protective” to “protection” within the standard to be consistent with Section G.
5. The SDT added a reference document for use in calculation of SSSL.

Several commentators were concerned that Section G has a prescribed method for illustrating coordination of AVR limiter/protection functions with other protection systems. The SDT agrees that there are numerous ways of demonstrating coordination, and does not prescribe any particular method. Any protective function that is enabled should be evaluated for proper coordination.

The SDT reviewed the requests to remove the distance relay and volts/hertz relay elements from the standard. It is the belief that these two elements remain in the document since a) the distance element should illustrate coordination with field-forcing controls of the AVR, and b) the volts per hertz function can operate with the unit on-line under certain operating conditions.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

Questions 1-4 relate to MOD-025-2, Questions 5-8 relate to MOD-027-1, and Questions 9-11 relate to PRC-019-1.

1. **The GVSDT has revised MOD-025-2 by splitting Requirement R1 into two requirements that allow for separate testing for real and reactive power. A paragraph was added to the start of Attachment 1 that further explains this point. Do you agree with this revision? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

2. **The GVSDT clarified the applicability of this standard to synchronous condensers greater than 20 MVA (nameplate rating). Do you agree with this applicability? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

3. **The GVSDT clarified that the data is to be submitted to the Transmission Planner by the Generator Owner or Transmission Owner. Do you agree with this? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

4. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-025-2?**

   Comments:

5. **The GVSDT has included partial load rejection testing in Part 2.1.1 subject to the conditions specified in footnote 5 (differences between the control mode tested and the final simulation model must be taken into account). Do you agree with the inclusion and footnote 5? If not, please explain in the comment area below.**

   ☐ Yes
   ☐ No
   Comments:

6. **The GVSDT has provided guidance on the periodicity aspects of Attachment 1. Do you agree? If not, please explain in the comment area below.**

   ☐ Yes
   ☐ No
   Comments:

7. **The GVSDT has address units which are always base loaded (by definition a base loaded unit is considered verified). This provides an exemption from verification for base load units. Do you agree? If not, please explain in the comment area below.**

   ☐ Yes
   ☐ No
   Comments:

8. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-027-1?**

   Comments:

9. **The GVSDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 20 MVA. The standard applies to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 20MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the comment area below.**

   ☐ Yes
   ☐ No
   Comments:

10. The GVSDT revised section G based on stakeholders' comments to provide clarity and to indicate that the items listed are examples of coordination and that entities may provide "Equivalent tables or other evidence." Do you agree with the revisions to Section G? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments:

11. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-019-1?**

Comments:

Project 2007-09 Generator Verification
Consideration of Issues and Directives

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval. The confusion centers on "approval" and when the 30-day period starts. 1311. We repeat our concern that Requirement R2, which specifies that the "regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval," is not clear. The requirement lacks a definition of what approval is required and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement. Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions	MOD-024-1; FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
can be determined. 1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary. 1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather		R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.		recorded for a staged test or the date the data is selected for verification using historical operational data
Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions can be determined. 1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The		The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner, including test conditions. Section 3 of Attachment is: 3. Record the following data for the verifications specified above: 3.1. The value of the gross Real and Reactive Power generating

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary. 1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate		capabilities at the end of the verification period. 3.2. The voltage schedule provided by the Transmission Operator. 3.3. The voltage at the high and low side of the GSU and/or system Interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated. 3.4. The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as: • Ambient air temperature • Relative humidity • Cooling water temperature 3.5. The date and time of the verification period, including start and end time in hours and minutes. 3.6. The existing GSU and/or system Interconnection transformer(s) tap setting. 3.7. The GSU transformer losses if the verification measurements were taken from the high side of the GSU transformer. 3.8. Whether the test data is a result of a staged test or if it is

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.		operational data.
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
Remove the fill-in-the-blank aspects (correct reference to "…Regional Reliability Organization's procedures…").	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Goal is uniform North American standards for real and reactive power verification. Look at regional requirements and identify the best practice, commonalities and differences, and whether differences are needed for reliability.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
No requirement for the RRO to demonstrate that its procedures result in accurate information of gross and net real power capability of generators for steady state models	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit	MOD-024-1; Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
Provide clarity where the Planning Authority is mentioned	MOD-024-1, Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.
Require verification of reactive power capability at multiple points over a unit's operating range. 1321. We disagree with commenters that verifying	MOD-025-1, FERC Order 693	Attachment 1 of MOD-025-2 addresses this directive. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW loading. However, other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.		Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data: 2.1. Verify Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour. 2.4. Collect the under-excited Reactive Power capability verification data identified in 2.1 and 2.2, and the over-excited Reactive Power capability verification data identified in 2.2 as soon as a limit is reached. 2.5. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure. 2.6. Collect the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval. The confusion centers on "approval" and when the 30-day period starts. 1322. We maintain the concern we expressed in the NOPR that Requirement R2 provides that the "regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval" and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.	MOD-025-1, FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1, R2 and R3 above.
Remove the fill-in-the-blank aspects (correct reference to "… Regional Reliability Organization's procedures…").	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Refer to MOD-024.	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards	MOD-025-1, Fill-in-the-blank	The GVSDT has combined MOD-024 and MOD-025 into a single

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	Team	standard, MOD-025-2.
These standards do not provide for uniform testing of generator capability. The determination of which units are tested, how frequently they are tested, and the criteria used for determining capability are left to individual regions.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
R1.5.1: The benefit of verifying maximum capability of generators to absorb VArs at seasonal real power generation capability is unclear, particularly if this standard applies to virtually all generators. For the vast majority of units, the need to absorb VArs occurs during low-load conditions, when unit real power production is below maximum capability and the unit's ability to absorb VArs is greater. Therefore, the single datum for unit VAr absorption capability determined pursuant to this standard seems to be of little practical use, except for relatively few generators in a limited set of circumstances.	MOD-025-1, Phase III/IV Team	The Standard no longer references "seasonal capability." Attachment 1 of MOD-025-2 describes the required testing. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve. If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		test, not operational data: 2.1. Verify Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.3. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour. 2.4. Collect the under-excited Reactive Power capability verification data identified in 2.1 and 2.2, and the over-excited Reactive Power capability verification data identified in 2.2 as soon as a limit is reached. 2.5. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure. 2.6. Collect the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. Please see Requirements R1, R2 and R3 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit.	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		a requirement.
Severity of non-compliance should be based on the percentage of the generator owner's total generation capability comprised of units required to be verified, rather than on the percentage (number) of generating units. Exempt units should be excluded from the total generation capability for determining level of non-compliance.	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
There is no clear reason for regional variations in capability testing. A generator in Georgia does not have more or less capability than an identical unit applied across the Florida line, despite the fact that one is in SERC and the other in FRCC.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard as well as regional variances have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Fundamental guidelines outlining some basic requirements (e.g., all units over 20 MW shall be tested annually under conditions that permit full net output of the unit for normal operation) are lacking.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. All required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Provide clarity where the Planning Authority is mentioned	MOD-025-1; Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Real Power Capability**

2. **Number:** MOD-024-1

3. **Purpose:** To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Effective Dates:**

   Requirement 1 and Requirement 2 **—** April 1, 2006.

   Requirement 3 — January 1, 2007.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Criteria for reporting generating unit auxiliary loads.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.

R1.4. Periodicity and schedule of model and data verification and reporting.

R1.5. Information to be verified and reported:

R1.5.1. Seasonal gross and net Real Power generating capabilities.

R1.5.2. Real power requirements of auxiliary loads.

R1.5.3. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Real Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Real Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to those procedures, for verification and reporting of generator gross and net Real Power capability were provided to affected Generator Owners, Generator Operators,

Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Real Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous versions of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2, R1.4

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: There shall be a level two non-compliance if **both** of the following conditions are present:

2.2.1 Procedures did not meet two of the following requirements: R1.1, R1.2, R1.4

2.2.2 No evidence that procedures were distributed as required in R2.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet either R1.5.1, R1.5.2 or R1.5.3

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a generator owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a generator owner's units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a generator owner's units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% of a generator owner's units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3. 8. Removed the word "less" after 94% in section 3.4. Level 4.	01/20/06

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Reactive Power Capability**

2. **Number:** MOD-025-1

3. **Purpose:** To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Effective Dates:**

   Requirement 1 and Requirement 2 — January 1, 2007

   Requirement 3:

   January 1, 2008 — 1st 20% compliant

   January 1, 2009 — 2nd 20% compliant

   January 1, 2010 — 3rd 20% compliant

   January 1, 2011 — 4th 20% compliant

   January 1, 2012 — 5th 20% compliant

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Criteria for reporting generating unit auxiliary loads.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.

R1.4. Periodicity and schedule of model and data verification and reporting.

R1.5. Information to be reported:

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.

R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.

R1.5.3. Verified Reactive Power of auxiliary loads.

R1.5.4. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the

Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Reactive Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to these procedures, for verification and reporting of generator gross and net Reactive Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Reactive Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous version of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2 or R1.4.

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: Procedures did not meet two or three of the following requirements: R1.1, R1.2 or R1.4.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet R1.5.1, R1.5.2, R1.5.3, or R1.5.4.

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a Generator Owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a Generator Owner's units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a Generator Owner's units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% less of a Generator Owner's units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3.	01/20/06

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2007-09 Generator Verification
MOD-024-1 DRAFT Mapping Document

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-024-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Real Power Capability.	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability.
3. Purpose: To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To require applicable entities verify generator Real and Reactive Power capability and Synchronous Condenser Reactive Power Capability and to supply capability date to planning entities data for assessing Bulk Electric System (BES) reliability.

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner with synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.
R1. The Regional Reliability	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined. Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, Applicability**,** which follows the Registry Criteria.	**4.2 Facilities:** 4.2.1 For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**Requirement R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	**Requirement R1** references **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be performed.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		the date the data is selected for verification using historical operational data.
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirement R1 references Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Real Power generating capabilities. **R1.5.2.** Real Power requirements of auxiliary loads.	**Requirement R1** references **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.5.3. Method of verification, including date and conditions.		containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Real Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

Project 2007-09 Generator Verification MOD-025-1 DRAFT Mapping Document

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-025-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Reactive Power Capability	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To require applicable entities verify generator Real and Reactive Power capability and Synchronous Condenser Reactive Power Capability and to supply capability date to planning entities data for assessing Bulk Electric System (BES) reliability.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner with synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.
R1. The Regional Reliability Organization	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, **Applicability,** which follows the Registry Criteria.	**4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the bulk power system. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the bulk power system.

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MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard. **Attachment 1,** section 4.1 allows engineering estimates in those situations where metering to measure a reactive load is not installed.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.**
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data,	**Requirements R2 and R3,** reference **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
commissioning data, performance tracking, and testing, etc.	performed.	**its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data**
R1.4. Periodicity and schedule of model	**Requirements R2 and R3,**	**R2. Each Generator Owner shall provide its Transmission**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
and data verification and reporting.	reference **Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	**Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Reactive Power generating capabilities while at the Seasonal Real Power generating capability as reported in accordance with MOD-024-2. **R1.5.2.** Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc. **R1.5.3** Verified Reactive Power of Auxiliary loads.	**Requirements R2 and R3,** reference **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.5.4. Method of verification, including date and conditions.		**Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data**
R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2** and **R3**.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		verification using historical operational data. **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data**
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Reactive Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2 and R3**. The Transmission Owner has been added to include	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
	synchronous condensers that are under the control of the TO.	**Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data**

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control; or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the BulkPower System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BulkPower System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup Facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and Facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical Facilities
- Appropriate use of transmission Loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4; whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for MOD-025-2:

There are three requirements in MOD-025-2. Each requirement was assigned a "Medium" VRF.

VRF for MOD-025-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each Requirement in MOD-025-1 is assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirements R2 and R3. Each requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC's definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R2:

- FERC Guideline 2 — Consistency within is similar in scope to Requirements R1 and R3. Each Requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept, and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit as specified in this standard.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each requirement in MOD-025-1 is assigned a “Medium” VRF. Requirement R3 is similar in scope to Requirements R1 and R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0, Requirements R1 and R2, in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC’s definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned “Medium” VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R3 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-025-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for MOD-025-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms, and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action, and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation, and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of V~~v~~iolation R~~r~~isk ~~f~~Factors (VRFs) and V~~v~~iolation S~~s~~everity L~~l~~evels (VSLs) for each requirement in MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved ~~Reliability Standard~~Reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard d~~D~~rafting t~~T~~eam applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to B~~b~~ulk E~~e~~lectric S~~s~~ystem instability, separation, or a cascading sequence of failures;~~,~~ or could place the ~~bulk electric system~~Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could;~~,~~ under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to ~~bulk electric system~~Bulk Electric System instability, separation, or a cascading sequence of failures;~~,~~ or could place the ~~bulk electric system~~Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures;~~,~~ or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the ~~bulk electric system~~Bulk Electric System;~~,~~ or the ability to effectively monitor and control the ~~bulk electric system~~Bulk Electric System. However, violation of a medium~~-~~-risk requirement is unlikely to lead to ~~bulk electric system~~Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could;~~,~~ under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System;~~,~~ or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. However, violation of a medium~~-~~-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to ~~bulk electric system~~Bulk Electric System instability, separation, or cascading failures;~~,~~ nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System;~~,~~ or the ability to effectively monitor and control the ~~bulk electric system~~Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System;~~,~~ or the ability to effectively monitor, control;~~,~~ or restore the ~~bulk electric system~~Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of ~~Reliability Standard~~Reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk~~-~~Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk~~-~~Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup F~~f~~acilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and F~~f~~acilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical F~~f~~acilities
- Appropriate use of transmission L~~l~~oading relief

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-r~~R~~equirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to r~~R~~equirements that address similar reliability goals in different r~~R~~eliability s~~S~~tandards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single r~~R~~equirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such r~~R~~equirements must not be watered down to reflect the lower risk level associated with the less important objective of the r~~R~~eliability s~~S~~tandard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4;~~,~~ w~~W~~hereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's r~~R~~eliability s~~S~~tandards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for MOD-025-2:
There are three~~wo~~ requirements in MOD-025-2. Each requirement was assigned a "Medium~~Lower~~" VRF.

VRF for MOD-025-2, Requirement R1:

- FERC Guideline 2 — Consistency within a r~~R~~eliability s~~S~~tandard exists. Each Requirement in MOD-025-1 is assigned a "~~Lower~~Medium" VRF. Requirement R1 ~~does not contain Parts and~~ is similar in scope to Requirements R2 and R3. Each r~~R~~equirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among ~~Reliability Standard~~reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept~~,~~ ~~and also MOD-004-1, Requirement R1~~ and they ~~that~~ have~~s~~ ~~an~~ approved Medium~~Lower~~ VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all F~~f~~acilities,

and not merely a single unit, as specified in this standard. ~~Experience easily demonstrates that the overall impact of verifying data for a single unit will not adversely impact the overall interconnection study results.~~

- FERC Guideline 4 — Consistency with NERC's d~~D~~efinition of the VRF l~~L~~evel selected exists. Failure to verify models in the l~~L~~ong-term p~~P~~lanning t~~T~~ime h~~H~~orizon is a requirement in a planning time frame that, if violated, ~~would not~~could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System;~~,~~ or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. Therefore, the assigned "~~Lower~~Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of r~~R~~equirements that c~~C~~o-mingle m~~M~~ore t~~T~~han o~~O~~ne o~~O~~bligation is satisfactory. The Requirement R1 risk objective is to verify capability. ~~Lower~~ The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The "~~Lower~~Medium" VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R2:

- FERC Guideline 2 — Consistency within is similar in scope to Requirements R1 and R3. Each Requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among Reliability Standard~~reliability standard~~s exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept, and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all F~~f~~acilities, and not merely a single unit as specified in this standard.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models ~~in the~~ is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System;~~,~~ or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. Therefore, the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of r~~R~~equirements that c~~C~~o-mingle m~~M~~ore t~~T~~han o~~O~~ne o~~O~~bligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The "Medium" VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R3~~2~~:

- FERC Guideline 2 — Consistency within a ~~Reliability Standard~~reliability standard exists. Each r~~R~~equirement in MOD-025-1 is assigned a "~~Lower~~Medium" VRF. Requirement R3~~2~~ ~~does not contain Parts and~~ is similar in scope to Requirements R1 and R2.
- FERC Guideline 3 — Consistency among ~~Reliability Standard~~reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0, Requirements R1 and R2, in concept ~~, and also MOD-004-1, Requirement R1~~ and they have~~that has an~~ approved ~~Lower~~ Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all F~~f~~acilities, and not merely a single unit, as specified in this standard. ~~Experience easily demonstrates that the overall impact of verifying data for a single unit will not adversely impact the overall interconnection study results.~~
- FERC Guideline 4 — Consistency with NERC's d~~D~~efinition of the VRF l~~L~~evel selected exists. Failure to verify models in the l~~L~~ong-term p~~P~~lanning t~~T~~ime h~~H~~orizon is a requirement in a planning time frame that, if violated, ~~would not~~could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System;~~,~~ or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. Therefore, the assigned "~~Lower~~Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of r~~R~~equirements that c~~C~~o-mingle m~~M~~ore t~~T~~han o~~O~~ne o~~O~~bligation is satisfactory. The Requirement R3~~2~~ risk objective is to verify capability. ~~Lower~~ The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The "~~Lower~~Medium" VRF assigned is based on the risk objective specified.

Justification for Assignment of Violation Severity Levels:
In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-025-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

~~. . .~~ U~~u~~nless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-025-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.~~incorporating binary VSL elements for requirement actions with~~	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; ~~submission timeliness~~ whereas, MOD-025-1 l~~L~~evels of n~~N~~on-c~~C~~ompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. ~~are binary with additional consideration for the obligation to submit information in a timely fashionobligation information submission timeliness~~. ~~Binary requirements are categorized as severe.~~ Proposed VSL language does not include ambiguous terms, and ensure uniformity and consistency in the determination of penalties based on binary performance	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action, and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation, and not a cumulative violation methodology.

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	~~additional consideration for the obligation to submit information submission in a timely fashioniness.~~		and obligation information submission timeliness.		

VSLs for MOD-025-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 l~~L~~evels of n~~N~~on-c~~C~~ompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R3~~2~~:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3~~2~~.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.~~incorporating~~	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion;~~obligation information submission timeliness~~ whereas, MOD-025-1 l~~L~~evels of n~~N~~on~~-~~c~~C~~ompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. ~~are binary with additional consideration for obligation information submission timeliness. Binary requirements are categorized as severe.~~ Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	~~binary VSL elements for requirement actions with additional consideration for obligation information submission timeliness.~~		based on binary performance and obligation information submission timeliness.		

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-027-1:
There are five requirements in MOD-027-1. Three requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-027-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This

requirement is administrative in nature for providing instructions and data used for performing model verification. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 which have an approved VRF of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contains Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The “Lower” VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The “Lower” VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R6 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-027-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for MOD-027-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is timely. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh’g and compliance filing, 120 FERC ¶ 61,145 (2007) (“VRF Rehearing Order”).

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-019-1:
There are two requirements in PRC-019-1 and both have been assigned a "High" VRF.

VRF for PRC-019-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts that are procedural in nature for satisfying the main requirement. The VRF is only applied at the Requirement level. The standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R1 is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. In addition, and as is generally the case with PRC standard VRF definitions, this requirement is assigned a "High" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric

system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Failure to periodically verify or following setting changes affecting coordination verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Therefore the assigned "High" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 and Part 1.1 have a high risk objective to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. The "High" VRF assigned is based on the high risk objective specified.

VRF for PRC-019-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts that are procedural in nature for satisfying the main requirement. The VRF is only applied at the Requirement level. The standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R2 is similar in concept with both PRC-010-0 Requirement R1 and PRC-014-0 Requirement R1, both of which require 5-year verification of protection coordination or settings. In addition, and as is generally the case with PRC standard VRF definitions, this requirement is assigned a "High" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Failure to periodically verify or following setting changes affecting coordination verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the

bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Therefore the assigned “High” VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 has a high risk objective to specify the periodicity for verifying voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. The “High” VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-019-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-019-1 Requirement R1:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements as the requirement has a reliability objective that is either met or not.	This is a new Requirement and does not have a prior level of compliance.	The proposed VSL is binary. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the procedure specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-019-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are based on increments of tardiness for competing required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the procedure specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-019-1:

There ~~is~~ are~~only~~ two~~one~~ requirements in PRC-019-1 and both~~it~~ has been assigned a "High" VRF.

VRF for PRC-019-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts that are procedural in nature for satisfying the main requirement. The VRF is only applied at the Requirement level. The standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R1 is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. ~~Requirement R1, Part 1.2 is similar in concept with both PRC-010-0 Requirement R1 and PRC-014-0 Requirement R1, both of which require 5-year verification of protection coordination or settings.~~ In addition, and as is generally the case with PRC standard VRF definitions, this requirement is assigned a "High" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative

conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Failure to periodically verify or following setting changes affecting coordination verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Therefore the assigned "High" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 and Part 1.1 have a high risk objective to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. ~~The Requirement R1, Part 1.2 has a high risk objective to specify the periodicity for verifying voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. Requirement Parts and obligations are lower risk procedural step elements that are administrative in nature for ensuring main requirement performance.~~ The "High" VRF assigned is based on the high risk objective specified.

VRF for PRC-019-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts that are procedural in nature for satisfying the main requirement. The VRF is only applied at the Requirement level. The standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R2 is similar in concept with both PRC-010-0 Requirement R1 and PRC-014-0 Requirement R1, both of which require 5-year verification of protection coordination or settings. In addition, and as is generally the case with PRC standard VRF definitions, this requirement is assigned a "High" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder

restoration to a normal condition. Failure to periodically verify or following setting changes affecting coordination verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Therefore the assigned "High" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 has a high risk objective to specify the periodicity for verifying voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. The "High" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-019-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for PRC-019-1 Requirement R1:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements as the requirement has a reliability objective that is either met or not ~~and identifying noncompliance of missing actions and obligations specified by listed Parts~~.	This is a new Requirement and does not have a prior level of compliance.	The ~~P~~proposed VSL~~'s~~ is ~~are a combination of~~ binary ~~elements with additional consideration for completeness of listed parts~~. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the procedure specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-019-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness..	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are based on increments of tardiness for competing required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the procedure specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Standards Announcement

Project 2007-09 Generator Verification

Ballot Windows Open for Three Ballots and Three Non-Binding Polls - April 6, 2012 through April 16, 2012

Available April 6

Initial ballots of MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability, MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions, and PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection, and non-binding polls of the associated VRFs and VSLs, are **open Friday, April 6 through 8 p.m. Eastern on Monday, April 16, 2012.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards and opinion for the non-binding polls by clicking here.

Special Instructions for Submitting Comments with a Ballot

Please note that comments submitted during the formal comment period, the ballot and the non-binding polls use the same electronic form. Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. Companies or entities with representatives in multiple segments of the ballot pool may submit a single set of comments by identifying themselves as a "group" on the comment form. Likewise, it is **preferable** for a group of separate entities that develop comments jointly to submit the comments as a "group." **The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form, and that companies in multiple segments as well as individual entities that develop joint comments with other entities submit their comments as a "group," with the list of group members and their associated Industry Segments.**

Next Steps

The drafting team will consider all comments and determine what changes to make in response to stakeholder input from the comments.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage ExcursionsMOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project webpage.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 Generator Verification

Two Ballot Windows Now Open Through March 29, 2012

Now Available

Successive ballots of MOD-026-1 – Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions and PRC-024-1 – Generator Performance During Frequency and Voltage Excursions, and non-binding polls of the associated VRFs and VSLs, are **open through 8 p.m. Eastern on Thursday, March 29, 2012.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards and opinions for the non-binding polls by clicking here.

Special Instructions for Submitting Comments with a Ballot

Please note that comments submitted during the formal comment period and the ballots for both standards all use the same electronic form. Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. Companies or entities with representatives in multiple segments of the ballot pool may submit a single set of comments by identifying themselves as a "group" on the comment form. Likewise, it is preferable for a group of separate entities that develop comments jointly to submit the comments as a "group." The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form, and that companies in multiple segments as well as individual entities that develop joint comments with other entities submit their comments as a "group."

Next Steps

The drafting team will consider all comments and determine what changes to make in response to stakeholder input from the comments.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage ExcursionsMOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

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Standards Announcement

Project 2007-09 Generator Verification

Ballot Pool Windows Open – Three Ballots and Three Non-binding Polls: Feb. 29 – Mar. 29, 2012
Two Formal Comment Periods Open:
MOD-026-1 & PRC-024-1 Feb. 29 – Mar. 29, 2012
PRC-019-1, MOD-025-2, & MOD-027-1 – Feb. 29 – Apr. 16, 2012
Ballot Windows Open – Two Ballots and Two Non-binding Polls:
(MOD-026-1 & PRC-024-1) March 19 – March 29, 2012
Ballot Windows Open – Three Ballots and Three Non-binding Polls:
PRC-019-1, MOD-025-2, & MOD-027-1) April 6 – April 16, 2012

Now available

The Generator Verification standard drafting team has posted five standards and their associated implementation plans for a formal comment period. Please read the following announcement carefully because, although the five standards are being posted together, they are at different stages in the standards process. In order to facilitate moving forward those standards that reach consensus, the standards are being balloted independently.

MOD-026-1 and PRC-024-1 Formal 30-day Comment Period, Successive Ballot and Non-binding Poll

Two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation Control System Functions , and PRC-024-1– Generator Performance During Frequency and Voltage Excursions, are posted for a 30-day formal comment period through March 29, 2012. A successive ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-026-1 and PRC-024-1 from March 19 through March 29, 2012. Please note that **separate ballot pools were formed for each standard and non-binding poll**.

Instructions for Commenting

Please use this electronic form to submit comments on MOD-026-1 and PRC-024-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit multiple separate sets of comments (one during the comment period and one with each ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

MOD-025-2, MOD-027-1, and PRC-019-1 Formal 45-day Comment Period and Ballot Pool Formation

Three additional standards have been posted for a 45-day formal comment period:

- MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability
- MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- PRC-019-1 – Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

An initial ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-025-1, MOD-027-1 and PRC-019-1 from April 6 through April 16, 2012. Please note that **separate ballot pools are being formed for each standard and non-binding poll**.

Ballot Pools Open through 8 a.m. EST on March 29, 2012 for MOD-025-2, MOD-027-1, and PRC-019-1 Ballots and Non-binding Polls

The Standards Committee has authorized posting these standards and their associated implementation plans for a 45-day formal comment period, with an initial ballot and concurrent non-binding poll conducted during the last 10 days of that comment period. A separate ballot pool is being formed for each standard and for each non-binding poll in order to allow NERC Registered Ballot Body members to selectively join those ballot pools in which they have an interest. To submit an opinion in a non-binding poll for any standard, you must join the ballot poll for that non-binding poll. Each of the six ballot pools will be open through 8 a.m. EST on March 29, 2012.

Instructions for Joining Ballot Pools for MOD-025-2, MOD-027-1, and PRC-019-1 Ballots and Non-binding Polls

NERC Registered Ballot Body members must join each of the ballot pools to be eligible to vote in the upcoming ballots and non-binding polls. Join

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

MOD-025-2 ballot	bp-2007-09_MOD-025-2_in@nerc.com
MOD-027-1 ballot	bp-2007-09_MOD-027-1_in@nerc.com
PRC-019-1 ballot	bp-2007-09_PRC-019-1_in@nerc.com

Instructions for Commenting

Please use this electronic form to submit comments on MOD-025-2, MOD-027-1, and PRC-019-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit multiple separate sets of comments (one during the comment period and one with each ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

Next Steps

Successive ballots of MOD-026-1 and PRC-024-1and concurrent non-binding polls of the associated VRFs and VSLs will begin on March 19, 2012 and end at 8 p.m. Eastern on March 29, 2012. Initial ballots of MOD-025-2, MOD-027-1 and PRC-019-1 and concurrent non-binding polls of the associated VRFs and VSLs will begin on Friday, April 6, 2012 and end at 8 p.m. Eastern on Monday, April 16, 2012. Following the formal comments periods for MOD-026-1, PRC-024-1, MOD-025-2, MOD-027-1, and PRC-019-1, the drafting team will consider all comments and determine whether to make changes to the standards, implementation plans, or associated VRFs and VSLs.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
  MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project web page.

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The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Announcement

Project 2007-09 Generator Verification

Ballot Pool Windows Open – Three Ballots and Three Non-binding Polls: Feb. 29 – Mar. 29, 2012

Two Formal Comment Periods Open:

MOD-026-1 & PRC-024-1 Feb. 29 – Mar. 29, 2012

PRC-019-1, MOD-025-2, & MOD-027-1 – Feb. 29 – Apr. 16, 2012

Ballot Windows Open – Two Ballots and Two Non-binding Polls:

(MOD-026-1 & PRC-024-1) March 19 – March 29, 2012

Ballot Windows Open – Three Ballots and Three Non-binding Polls:

PRC-019-1, MOD-025-2, & MOD-027-1) April 6 – April 16, 2012

Now available

The Generator Verification standard drafting team has posted five standards and their associated implementation plans for a formal comment period. Please read the following announcement carefully because, although the five standards are being posted together, they are at different stages in the standards process. In order to facilitate moving forward those standards that reach consensus, the standards are being balloted independently.

MOD-026-1 and PRC-024-1 Formal 30-day Comment Period, Successive Ballot and Non-binding Poll

Two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation Control System Functions , and PRC-024-1– Generator Performance During Frequency and Voltage Excursions, are posted for a 30-day formal comment period through March 29, 2012. A successive ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-026-1 and PRC-024-1 from March 19 through March 29, 2012. Please note that **separate ballot pools were formed for each standard and non-binding poll**.

Instructions for Commenting

Please use this electronic form to submit comments on MOD-026-1 and PRC-024-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit multiple separate sets of comments (one during the comment period and one with each ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

MOD-025-2, MOD-027-1, and PRC-019-1 Formal 45-day Comment Period and Ballot Pool Formation

Three additional standards have been posted for a 45-day formal comment period:

- MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability
- MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- PRC-019-1 – Coordination of Generating Unit or Plant Voltage Regulating Controls with Generating Unit or Plant Capabilities and Protection

An initial ballot and non-binding poll of the associated VRFs and VSLs will be conducted for MOD-025-1, MOD-027-1 and PRC-019-1 from April 6 through April 16, 2012. Please note that **separate ballot pools are being formed for each standard and non-binding poll**.

Ballot Pools Open through 8 a.m. EST on March 29, 2012 for MOD-025-2, MOD-027-1, and PRC-019-1 Ballots and Non-binding Polls

The Standards Committee has authorized posting these standards and their associated implementation plans for a 45-day formal comment period, with an initial ballot and concurrent non-binding poll conducted during the last 10 days of that comment period. A separate ballot pool is being formed for each standard and for each non-binding poll in order to allow NERC Registered Ballot Body members to selectively join those ballot pools in which they have an interest. To submit an opinion in a non-binding poll for any standard, you must join the ballot poll for that non-binding poll. Each of the six ballot pools will be open through 8 a.m. EST on March 29, 2012.

Instructions for Joining Ballot Pools for MOD-025-2, MOD-027-1, and PRC-019-1 Ballots and Non-binding Polls

NERC Registered Ballot Body members must join each of the ballot pools to be eligible to vote in the upcoming ballots and non-binding polls. Join

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

MOD-025-2 ballot	bp-2007-09_MOD-025-2_in@nerc.com
MOD-027-1 ballot	bp-2007-09_MOD-027-1_in@nerc.com
PRC-019-1 ballot	bp-2007-09_PRC-019-1_in@nerc.com

Instructions for Commenting

Please use this electronic form to submit comments on MOD-025-2, MOD-027-1, and PRC-019-1. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit multiple separate sets of comments (one during the comment period and one with each ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

Next Steps

Successive ballots of MOD-026-1 and PRC-024-1and concurrent non-binding polls of the associated VRFs and VSLs will begin on March 19, 2012 and end at 8 p.m. Eastern on March 29, 2012. Initial ballots of MOD-025-2, MOD-027-1 and PRC-019-1 and concurrent non-binding polls of the associated VRFs and VSLs will begin on Friday, April 6, 2012 and end at 8 p.m. Eastern on Monday, April 16, 2012. Following the formal comments periods for MOD-026-1, PRC-024-1, MOD-025-2, MOD-027-1, and PRC-019-1, the drafting team will consider all comments and determine whether to make changes to the standards, implementation plans, or associated VRFs and VSLs.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project web page.

Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 – Generator Verification

Initial Ballot Results

Now Available

Initial ballots of three Generator Verification standards and non-binding polls of the associated VRFs and VSLs concluded Monday, April 16, 2012:

- MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
- MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Voting statistics for each ballot are listed below, and the Ballots Results page provides a link to the detailed results.

Standard	Quorum	Non-binding Poll Results
MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	Quorum: 88.28% Approval: 41.09%	Quorum: 86.82% Supportive Opinions: 43.72%
MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	Quorum: 88.04% Approval: 36.84%	Quorum: 86.04% Supportive Opinions: 38.56%
PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	Quorum: 88.04% Approval: 48.70%	Quorum: 86.53% Supportive Opinions: 46.38%

Next Steps

The drafting team will consider all comments submitted and make revisions to the standards and other documents to respond to the comments. If the drafting team decides to make substantive revisions, the drafting team will submit the revised standards and consideration of comments received for a quality review prior to posting for a parallel formal 30-day comment period and successive ballot.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid-2006 through mid-2007:

- PRC-019-1 — Coordination of Generating Unit or Plant Capabilities , Voltage Regulating Controls, and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project webpage.

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The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

User Name
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-Ballot Pools
-Current Ballots
-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2007-09 MOD-025-2
Ballot Period:	4/6/2012 - 4/16/2012
Ballot Type:	Initial
Total # Votes:	324
Total Ballot Pool:	367
Quorum:	**88.28 % The Quorum has been reached**
Weighted Segment Vote:	41.09 %
Ballot Results:	**The drafting team will consider comments.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	32	0.438	41	0.562	6	11
2 - Segment 2.	9	0.6	2	0.2	4	0.4	0	3
3 - Segment 3.	82	1	20	0.282	51	0.718	4	7
4 - Segment 4.	27	1	9	0.409	13	0.591	3	2
5 - Segment 5.	92	1	33	0.465	38	0.535	10	11
6 - Segment 6.	50	1	14	0.341	27	0.659	2	7
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.6	3	0.3	3	0.3	1	0
9 - Segment 9.	3	0.1	0	0	1	0.1	1	1
10 - Segment 10.	7	0.6	4	0.4	2	0.2	0	1
Totals	**367**	**6.9**	**117**	**2.835**	**180**	**4.065**	**27**	**43**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Negative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	View
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	CPS Energy	Richard Castrejana	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	View
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Negative	View
1	M & A Electric Power Cooperative	William Price	Negative	View
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	View
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Negative	View
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	View
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	View
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	View
1	Salt River Project	Robert Kondziolka	Affirmative	

1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	View
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Negative	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	Central Electric Power Cooperative	Adam M Weber	Negative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	View
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	View
3	Great River Energy	Brian Glover	Negative	View
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	View

3	Lakeland Electric	Norman D Harryhill	Negative	View
3	Lincoln Electric System	Jason Fortik	Negative	View
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Jeff Franklin	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	View
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	View
3	Salt River Project	John T. Underhill		
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	View
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	View
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Flathead Electric Cooperative	Russ Schneider	Negative	View
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	View
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	View

4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Dairyland Power Coop.	Tommy Drea	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown	Affirmative	View
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	ICF International	Brent B Hebert	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	Invenergy LLC	Alan Beckham	Abstain	
5	JEA	John J Babik	Negative	View
5	Kansas City Power & Light Co.	Brett Holland	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Negative	View
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	View

5	Omaha Public Power District	Mahmood Z. Safi	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	View
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tacoma Power	Claire Lloyd	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	View
6	FirstEnergy Solutions	Kevin Querry	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	View
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	View

6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	View
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Westar Energy	Grant L Wilkerson	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner	Negative	View
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Abstain	
9	New York State Department of Public Service	Thomas Dvorsky		
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Negative	View
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2007-09 MOD-027-1
Ballot Period:	4/6/2012 - 4/16/2012
Ballot Type:	Initial
Total # Votes:	324
Total Ballot Pool:	368
Quorum:	**88.04 % The Quorum has been reached**
Weighted Segment Vote:	36.84 %
Ballot Results:	**The drafting team will consider comments.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	92	1	29	0.392	45	0.608	6	12
2 - Segment 2.	9	0.6	0	0	6	0.6	0	3
3 - Segment 3.	82	1	17	0.25	51	0.75	7	7
4 - Segment 4.	27	1	5	0.25	15	0.75	5	2
5 - Segment 5.	91	1	22	0.333	44	0.667	13	12
6 - Segment 6.	50	1	13	0.317	28	0.683	3	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.6	4	0.4	2	0.2	1	0
9 - Segment 9.	3	0.2	2	0.2	0	0	0	1
10 - Segment 10.	7	0.5	4	0.4	1	0.1	1	1
Totals	**368**	**6.9**	**96**	**2.542**	**192**	**4.358**	**36**	**44**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	View
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	CPS Energy	Richard Castrejana	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Negative	View
1	FirstEnergy Corp.	William J Smith	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	View
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	View
1	M & A Electric Power Cooperative	William Price	Negative	View
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	View
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Negative	View
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	View
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Jen Fiegel	Negative	View
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	View
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Negative	View
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	View
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Consumers Energy	Richard Blumenstock	Negative	View
3	Cowlitz County PUD	Russell A Noble	Abstain	View
3	CPS Energy	Jose Escamilla	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	View
3	Detroit Edison Company	Kent Kujala	Negative	View
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	View
3	Great River Energy	Brian Glover	Negative	View
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	View

3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	View
3	Lakeland Electric	Norman D Harryhill	Negative	View
3	Lincoln Electric System	Jason Fortik	Negative	View
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Jeff Franklin	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	View
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	View
3	Salt River Project	John T. Underhill		
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	View
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Abstain	View
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	View
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	View
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View
4	Public Utility District No. 1 of Snohomish	John D Martinsen	Negative	View

	County			
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	View
5	Cowlitz County PUD	Bob Essex	Abstain	View
5	Dairyland Power Coop.	Tommy Drea	Negative	View
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Negative	View
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs	Negative	View
5	Essential Power, LLC	Patrick Brown	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	ICF International	Brent B Hebert		
5	Imperial Irrigation District	Marcela Y Caballero	Abstain	
5	Invenergy LLC	Alan Beckham	Abstain	
5	JEA	John J Babik	Negative	View
5	Kansas City Power & Light Co.	Brett Holland	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Negative	
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5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
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5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	View
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5	Northern Indiana Public Service Co.	William O. Thompson		

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5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
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5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	View
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	View
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tacoma Power	Claire Lloyd	Negative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Dominion Resources, Inc.	Louis S. Slade	Negative	View
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	View
6	FirstEnergy Solutions	Kevin Querry	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	View
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	View
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Negative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	View
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Westar Energy	Grant L Wilkerson	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Brendan Kirby	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	New York State Department of Public Service	Thomas Dvorsky		
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

Ballot Results	
Ballot Name:	Project 2007-09 PRC-019-1
Ballot Period:	4/6/2012 - 4/16/2012
Ballot Type:	Initial
Total # Votes:	324
Total Ballot Pool:	368
Quorum:	**88.04 % The Quorum has been reached**
Weighted Segment Vote:	48.70 %
Ballot Results:	**The drafting team will consider comments.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	94	1	39	0.513	37	0.487	5	13
2 - Segment 2.	9	0.6	3	0.3	3	0.3	0	3
3 - Segment 3.	83	1	27	0.365	47	0.635	3	6
4 - Segment 4.	25	1	8	0.381	13	0.619	2	2
5 - Segment 5.	90	1	31	0.449	38	0.551	9	12
6 - Segment 6.	50	1	19	0.452	23	0.548	2	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.6	4	0.4	2	0.2	1	0
9 - Segment 9.	3	0.1	0	0	1	0.1	1	1
10 - Segment 10.	7	0.6	5	0.5	1	0.1	0	1
Totals	**368**	**6.9**	**136**	**3.36**	**165**	**3.54**	**23**	**44**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	View
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	CPS Energy	Richard Castrejana	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	View
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	View
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Negative	View
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	View
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	View
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	View
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	View
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	View
3	Great River Energy	Brian Glover	Negative	View
3	Gulf Power Company	Paul C Caldwell	Negative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Negative	View

3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	View
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	View
3	Lakeland Electric	Norman D Harryhill	Negative	View
3	Lincoln Electric System	Jason Fortik	Negative	View
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Jeff Franklin	Negative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	View
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	View
3	Salt River Project	John T. Underhill		
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	View
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	View
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Negative	View
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	View
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	View
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	View

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Dairyland Power Coop.	Tommy Drea	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs	Negative	
5	Essential Power, LLC	Patrick Brown	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	ICF International	Brent B Hebert		
5	Imperial Irrigation District	Marcela Y Caballero	Negative	
5	Invenergy LLC	Alan Beckham	Abstain	
5	JEA	John J Babik	Negative	View
5	Kansas City Power & Light Co.	Brett Holland	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	View
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson		

5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Negative	View
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	View
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tacoma Power	Claire Lloyd	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Negative	View
5	Tennessee Valley Authority	David Thompson	Negative	View
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
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6	Exelon Power Team	Pulin Shah	Negative	View
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	View
6	Imperial Irrigation District	Cathy Bretz	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	View
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	View
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Brendan Kirby	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Abstain	
9	New York State Department of Public Service	Thomas Dvorsky		
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

Non-binding Poll Results

Project 2007-09: MOD-025-2

Ballot Results	
Non-binding Poll Name:	Project 2007-09 MOD-025-2 Non-binding Poll
Poll Period:	4/6/2012 - 4/16/2012
Total # Opinions:	303
Total Ballot Pool:	349
Summary Results:	86.82% of those who registered to participate provided an opinion or abstention; 43.72% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	Central Electric Power Cooperative	Michael B Bax	Negative	View
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		

1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	View
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Negative	View
1	M & A Electric Power Cooperative	William Price	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	View
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Negative	View
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	

1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Negative	

3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Danny Lindsey	Affirmative	View
3	Great River Energy	Brian Glover	Negative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Norman D Harryhill	Negative	View
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	

3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		

5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Dairyland Power Coop.	Tommy Drea	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	ICF International	Brent B Hebert		
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	JEA	John J Babik	Negative	View
5	Kansas City Power & Light Co.	Brett Holland	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Abstain	

5	New York Power Authority	Wayne Sipperly	Negative	View
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Abstain	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	

6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	View
6	FirstEnergy Solutions	Kevin Querry	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	View
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	View
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner	Negative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

Non-binding Poll Results

Project 2007-09: MOD-027-1

Ballot Results	
Non-binding Poll Name:	Project 2007-09 MOD-027-1 Non-binding Poll
Poll Period:	4/6/2012 - 4/16/2012
Total # Opinions:	302
Total Ballot Pool:	351
Summary Results:	86.04% of those who participated provided an opinion or abstention; 38.56% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	Central Electric Power Cooperative	Michael B Bax	Negative	View
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	

1	FortisBC	Curtis Klashinsky		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	View
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	View
1	M & A Electric Power Cooperative	William Price	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	View
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Negative	View
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	View
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	

NERC

1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	

3	Consumers Energy	Richard Blumenstock	Negative	View
3	Cowlitz County PUD	Russell A Noble	Abstain	View
3	CPS Energy	Jose Escamilla	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	View
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Danny Lindsey	Affirmative	View
3	Great River Energy	Brian Glover	Negative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	View
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Norman D Harryhill	Negative	View
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	

3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	View
3	Snohomish County PUD No. 1	Mark Oens	Negative	View
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Abstain	View
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	

5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	View
5	Cowlitz County PUD	Bob Essex	Abstain	View
5	Dairyland Power Coop.	Tommy Drea	Negative	View
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs	Negative	View
5	Essential Power, LLC	Patrick Brown	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	ICF International	Brent B Hebert		
5	Imperial Irrigation District	Marcela Y Caballero	Abstain	
5	JEA	John J Babik	Negative	View
5	Kansas City Power & Light Co.	Brett Holland	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	

5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	View
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Negative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	

6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	View
6	FirstEnergy Solutions	Kevin Querry	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	View
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	View
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
8		James A Maenner	Affirmative	
8		Brendan Kirby	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	

8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

Non-binding Poll Results

Project 2007-09: PRC-019-1

Ballot Results	
Non-binding Poll Name:	Project 2007-09 PRC-019-1 Non-binding Poll
Poll Period:	4/6/2012 - 4/16/2012
Total # Opinions:	302
Total Ballot Pool:	349
Summary Results:	86.53% of those who registered to participate provided an opinion or abstention; 46.38% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	Central Electric Power Cooperative	Michael B Bax	Negative	View
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	

1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	View
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Negative	View
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	

1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	View
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Negative	View
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	View
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View

3	CPS Energy	Jose Escamilla	Negative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	View
3	Great River Energy	Brian Glover	Negative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Negative	View
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	View
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Norman D Harryhill	Negative	View
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	View
3	Ocala Electric Utility	David Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	

3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	View
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres	Negative	View
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	View
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View

5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Dairyland Power Coop.	Tommy Drea	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs	Negative	
5	Essential Power, LLC	Patrick Brown	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	View
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	ICF International	Brent B Hebert		
5	Imperial Irrigation District	Marcela Y Caballero	Negative	
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	View

5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	View
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	RANDY A YOUNG	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	

6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Negative	View
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	View
6	Imperial Irrigation District	Cathy Bretz	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	View
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
8		James A Maenner	Affirmative	
8		Brendan Kirby	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts	Donald Nelson	Negative	

	Department of Public Utilities			
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

Individual or group. (56 Responses)
Name (34 Responses)
Organization (34 Responses)
Group Name (22 Responses)
Lead Contact (22 Responses)
Contact Organization (22 Responses)
Question 1 (51 Responses)
Question 1 Comments (56 Responses)
Question 2 (49 Responses)
Question 2 Comments (56 Responses)
Question 3 (50 Responses)
Question 3 Comments (56 Responses)
Question 4 (0 Responses)
Question 4 Comments (56 Responses)
Question 5 (41 Responses)
Question 5 Comments (56 Responses)
Question 6 (41 Responses)
Question 6 Comments (56 Responses)
Question 7 (43 Responses)
Question 7 Comments (56 Responses)
Question 8 (0 Responses)
Question 8 Comments (56 Responses)
Question 9 (43 Responses)
Question 9 Comments (56 Responses)
Question 10 (39 Responses)
Question 10 Comments (56 Responses)
Question 11 (0 Responses)
Question 11 Comments (56 Responses)

Group
Pepco Holdings Inc and Affiliates
David Thorne
Pepco Holdings Inc.
No comment
No
Agree with the generating unit nameplate thresholds as defined in this standard and the compliance registry, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and

(B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition. Of course, Synchronous condensers are not spelled out either in the Compliance Registry, or the BES definition, and therefore they will have to be addresses separately in 4.2.2 as “Individual Synchronous Condensers greater than 20MVA (gross nameplate rating) directly connected at the point of interconnection at 100kV or above. “
No comment
No comment
Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds

in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition.
No
Same comments as in Question 2.
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
No
Attachment 1 requires a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% that is expected to last more than 6 months within 12 months. This is an excessive period of time for a generator to be providing less than expected Real or Reactive power output. Also, Attachment 1 requires staged verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.). • The data requested in this Standard will verify a generator’s capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data for both under-excited and over-excited field conditions will result in 4 specific data points that can assist TP’s in system studies. The GO can obtain this data by planning on doing the maximum lagging and leading tests when system conditions allow to measure the 4 specific data points desired. • “Separate tests” are not explained except for the statement “separate testing is allowed for this standard” which is in Attachment 1. What constitutes “separate testing”?
No
The data requested in this Standard will verify a generator’s capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, synchronous condensers should be removed from MOD-025.
No
The Reliability Coordinator is the entity that should receive this data. There are instances where a number of entities are registered as Transmission Planners. To avoid confusion this data should be submitted to a single entity who will then

distribute the data. Transmission Planner should be added to the Applicability Section 4.1 Functional Entities.
This testing will be difficult to stage due to the four point reactive power testing. The power system may have to be reconfigured in many cases to allow for the changes in generator reactive power output, and the testing may not be able to be carried out when planned. System disturbances can occur that will disrupt the testing. For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are “on-line”. For reactive testing, this would be better stated as 90% of the plant’s available capability considering that some wind turbines may be able to produce/absorb reactive power with no real power production. Does “on-line” just imply that the wind turbine breaker is closed and no requirement for real power production? In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power connected at the high-side of the generator step-up transformer (point D), and Aux or Station Service Real Power connected at other points of interconnection (point E). Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)? The data requested in this Standard will verify a generator’s capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies (and not include synchronous condensers). Therefore, the Purpose Statement be edited to read: • “To assure accurate information on generator gross and net Real and Reactive Power capability Reactive Power capability is available for planning models used to assess BES reliability.” The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime, unless the generator has been rewound, cooling systems modified, installation of a new exciter, etc. Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? A GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. 2. Comments on Attachments 1 and 2: • The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. • Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. • Notes 1 – 4 at the end of Attachment 1 should be removed from the Standard and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. • Section 4.2.1 (and elsewhere): the term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability Sections is confusing.
No
The footnote regarding partial load rejection testing is footnote 4, not 5. The

footnote should be removed and the language in 2.1.1 be revised. • 2.1.1 Documentation comparing the applicable unit's model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled.
Yes
No
Base loaded units could provide governor response for over-frequency events and should have verified models for this event. The term "base loaded" is not defined in MOD-027.
Some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical. The intent and goal of the SDT and MOD-027 are to achieve more accurate system modeling, and are to be supported. Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this what is intended? R2: There is linkage between the parenthetical "(within 365 calendar days from the date that the response was recorded)" and the reference in 2.2.1 "…unit's model response to the recorded response for either….", but this language is not clear. The term "response" in the parenthetical needs to be clarified. R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. Recommend the following wording to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc.), and any protection system controls (i.e. emission control systems on combustion turbines, etc.) effects of outer loop controls (such as operator set point

controls, and load control but excluding AGC control) that override the governor response (including blocked or non-functioning governors or modes of operation that limit the frequency response) if applicable. R3: First bullet, term “usable” should be revised to “usable as defined in Requirement 5”. Note that R5.1, 5.2 and 5.3 clearly define the criteria for “usable”. Section G References: Delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard.
No
This Standard is applicable to generating units/facilities that meet the compliance registry criteria. However, this Standard is not applicable to any type of synchronous condensers. The purpose for synchronous condensers is to provide voltage support as needed, similar in function to a capacitor bank or shunt reactor.
Yes
This Standard is written to verify coordination of generating unit Facility or synchronous voltage regulator controls, limit functions, equipment capabilities and Protection Systems. The Standard, as written, may apply to more generation than intended. The Standard as currently written protects the BPS and applies to generation units that are required to register with NERC in accordance with the Statement of Compliance Registry Criteria (SCRC). The approval of a new BES definition by FERC will define new more limiting inclusion criteria than the (SCRC) for generators and therefore will change the population of generators material to the BES. The unintended consequence is that the current wording of the Standard protects the BPS not the BES and uses the SCRC for defining applicable generators, not the BES definition generator Inclusion Criteria. The Standard in its current form will apply to generators that will not be considered material to the BES and not necessary for the reliability of the Transmission System. Section 4.2.1: term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the NERC defined term.
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
Southwest Power Pool
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
• The data requested in this Standard will verify a generators capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data both under and over excited field conditions will result in 4 specific data points that can assist TP's in system studies. For example, the GO can obtain this data by: o The maximum lagging and then leading test at full load may be performed during a high load day to obtain two data points. o The maximum lagging and then leading test at minimum load may be performed during the evening to two data points. • We could not find a paragraph explaining separate tests except for the statement "separate testing is allowed for this standard". So no, we don't agree with this revision. Attachment 1 requires verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.).
No
The data requested in this Standard will verify a generators capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, we recommend that synchronous condensers be removed from MOD-025.
Yes
Please add the TP in the Functional Entities in section 4.1.
Comments: 1. The data requested in this Standard will verify a generators capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies. Therefore, we recommend that the Purpose Statement be edited should read - • "To assure

accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BES reliability.” • The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime, unless the generator has been rewound, cooling systems modified, new exciter, etc. • Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. Is this the SDT’s understanding? 2. Comments on Attachments 1 and 2: • The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. • Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. • Notes 1 – 4 at the end of Attachment 1 should be removed from the Standard and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. • Section 4.2.1: term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing.
No
We believe the footnote regarding partial load rejection testing is footnote 4, not 5. We recommend the footnote be removed and the language in 2.1.1 be revised. 2.1.1: This requirement needs additional clarity. In one sentence, 2 on-line options and 1 off-line testing option have been proposed that compare the actual response to the model response. We recommend the following edits which provide more clarity and eliminate Footnote 4. • 2.1.1 Documentation comparing the applicable unit’s model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled.
No
The term “base loaded” is not defined in MOD-027.
Comments: Yes • Con Edison strongly supports the intent and goal of MOD-027 and the SDT efforts to achieve more accurate system modeling. • Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. • Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should

be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. • Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. • Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance. We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this the SDT's understanding? • R2: we believe that there is linkage between the parenthetical "(within 365 calendar days from the date that the response was recorded)" and the reference in 2.2.1 "...unit's model response to the recorded response for either....", but this language is not clear. The SDT is encouraged to clarify what the term "response" in the parenthetical is referring to. • R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. We recommend the following verbiage to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc) and any protection system controls (i.e. emission control systems on combustion turbines, etc) [delete: effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that override the governor response (including blocked or nonfunctioning governors or modes of operation that limit] the frequency response if applicable. • R3: first bullet, term "usable" should be revised to "usable as defined in Requirement 5". Note that R5.1, 5.2 and 5.3 clearly define the criteria for "usable". • Section G References: delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard.
• Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the NERC defined term.
Individual
Brenda Hampton
Luminant Energy Company LLC
Yes
Yes
Yes
Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power

capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section 3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2). On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope. Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the simplified one-line diagram …" Generator Owners can fill in the appropriate quantities at locations A-F. As an example, on some units values would be input for A, B, and F and NA entered for C, D, and E. For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard.
Yes
Yes
No
Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and include the exemption that excludes units that are base loaded. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3).
Yes
No
Luminant disagrees with the need to illustrate coordination of the phase distance

relay with AVR controls. The sample R-X diagram does not indicate how the relay is coordinated with field forcing capability. Since this function is covered in the generator loadability standard currently under development, Luminant recommends that this function be removed from the R-X diagram.
Luminant recommends in Requirement R1 that the coordination with Protection System be modified to reference the “applicable Protection System devices as referenced in Section G”. As written, Protection System is all inclusive and would require verification of settings beyond the scope of this standard.
Individual
Dan Roethemeyer
Dynegy
Yes
Yes
Yes
No
Yes
Yes
No
We don't understand the question. The two sentences seem to contradict themselves.
The division of responsibility (between GO and TP) in the task of ‘verifying’ the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and ‘verify’ the models. This would also eliminate the question of what constitutes a ‘verified’ model, i.e., how good is good enough.
Yes
Yes
No
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes

Yes
Yes
Sections 4.2.1, 4.2.2, 4.2.3 uses the term "bulk power system." should this be changed to "Bulk Electric System." Attachment I, "Verification specifications for applicable Facilities", #2. The third sentence should be revised to read "... at least 50 percent of the REACTIVE capability ..." Also, in the VSL section: R1, Moderate VSL should read "34 to 66 percent of the data." R1, R2, R3 Severe VSL should read "greater than 15 calendar months."
Yes
The footnotes in the redline and clean versions of MOD-027-1 have different numbering.
Yes
Yes
Yes
Yes
Individual
Martin Kaufman
ExxonMobil Research and Engineering
Yes
No
The SDT should clarify that a Synchronous Condenser is not a Synchronous Motor. Synchronous condensers are operated to provide Voltage Support to the bulk electric system through the production of VARS. A Synchronous Motor is theoretically the same piece of equipment with one exception; in a modern industrial electric distribution system, a Synchronous Motor's purpose is to drive a mechanical load while remaining VAR neutral (or closes to it). As written, industrial facilities that are registered as Generator Owners and operate large Synchronous Motors may be required to comply with this standard and be unable to comply with this standard due to the nature of the equipment that operates the Synchronous Motor's excitation system.
Yes
Yes

No
A model’s validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit’s response.
Yes
No
: A model’s validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit’s response.
Yes
Group
Tennessee Valley Authority - GO/GOP
David Thompson
NERC Reliability & Assessments
Yes
Yes
Yes
Testing a unit to the limits of its’ protective function (such as overvoltage) creates the possibility for an unplanned unit trip. The SERC Regional Criteria for MOD-024 and MOD-025 allows an engineering assessment in conjunction with operational data review as a valid verification method. MOD-025-2 should include an engineering assessment as a valid method of verification.
Yes
Yes
Yes

Some consideration should be given for sister units if it can be demonstrated that the governor controls have identical settings. The 5% capacity factor threshold may be lower than necessary. Consider at least a 10% threshold since units which operate that infrequently are unlikely to be on line when a BES event occurs.
No
The MVA criteria included in MOD-026-1 and MOD-027-1 are more appropriate for this standard than the 20 MVA criteria presently used. A 20 MVA unit is not critical enough to the BES reliability to justify this level of documentation of coordination. Standard PRC-004 already requires an investigation into relay misoperations for units greater than 20 MVA which would be the result of coordination issues.
Yes
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Yes
Please consider the following comments: Attachment 1, Periodicity for new verification Item 3 – Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or mutually agreed verification date." Attachment 1, Verification Specifications Item 2.1 - There appears to be a typographical error near the end of Item 2.1, we believe that it should state, "Retest the facility within six months of being unable to reach the 90 percent threshold". Attachment 1, Verification Specifications, Item 4.1, Note 1 – Consider deleting the last sentence because it contradicts the purpose of the standard, contracts the sentiment of Note 2, and will likely to be untrue after verified values are entered into the Transmission Planner's database and are submitted according to MOD-010.
Yes
Yes
Yes
ATC agrees with the exception for base load units, however, recommends adding text that explicitly highlights that the second to last item in "Event Triggering Verification" column refers to base loaded units such as, "New or existing base loaded units that are normally not responsive to a frequency excursion event".

Please consider the following comments: 1. Applicability, 4.2.1, bullet 1 – As a Transmission Planner, ATC recommends that the unit size value be “20 MVA” rather than “100 MVA” and the aggregate plant size value be “75 MVA” rather than 100 MVA” to agree with the NERC Compliance Registry Criteria, which implies that the 20 MVA unit size and 75 MVA plant size values are large enough to be subject to the Reliability Standards. We are not aware of a definitive study that found the 100 MVA value to be appropriate for the Eastern Interconnection, particularly the upper Midwest portion of the system. 2. In Requirements, R1, bullet 2 –ATC recommends to change the wording to, “obtain dynamic turbine/governor, load control, and active power/frequency control model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations”. Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. Requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets, depending on the Generator Owner licenses or lack of licenses.
Yes
Yes
Group
Arizona Public Service Company
Janet Smith
Arizona Public Service Company Regulatory Compliance
Yes
Yes
Yes
Need for real power verification and reliability benefits are not clear. Similarly need for and reliability benefits of all the detailed calculations are not clear. The drafting team should poll the industry as to the reliability benefits and determine out who will use the information and what is the benefit of such detailed reporting.
Yes
Yes
Yes

Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes
Even if the requirements are somewhat redundant, there are a number of important differences between Real and Reactive Power validations. In addition, there is a need to allow Generator Owners to address each separately if they should so choose. For example, a Real Power validation may be easily handled through actual operations data, while Reactive Power validations may need coordinated testing with the interconnected Transmission Operator. Under a single requirement, there is a risk that Compliance Authorities will assume that every test must be performed at the same time – using the same method.
No
Ingleside Cogeneration LP believes that MOD-025-2 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System – and this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of the BES takes effect.
Yes
Ingleside Cogeneration LP agrees that the proper recipient is the Transmission Planner. There is no reliability reason that we are aware of to include Transmission Owner in the loop – as the previous version of MOD-025-2 called for.
Ingleside Cogeneration LP is concerned that there is no apparent provision in MOD-025-2 should a restriction in the extent of Reactive Power validation testing be placed upon the GO or TO by the Transmission Operator. In many cases, the TOP cannot allow the local system to operate beyond a certain Power Factor – especially when the system is supplying reactive power to the generator (leading). It may be the project team's intent that such a limitation is expected to be captured as a "Remark" in the reporting template (Attachment 2). However, we believe that the requirements must include allowable exceptions – as that is what Compliance Authorities will use to assess compliance. Secondly, Measure 1 calls for a Generator Owner to provide correction factors for ambient conditions within 90 days of a request from the Transmission Planner. We agree with the reliability need, but believe there should be corresponding enforceable language in the requirement. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-025-2, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise

can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities.
Yes
Ingleside Cogeneration LP agrees that there must be viable options available in the event that a frequency excursion of the appropriate magnitude was not captured during the validation time frame. This may be more applicable to smaller generation facilities, or those which have a small capacity factor and are rarely online. We also agree that some further analysis may be required to account for the difference in operating conditions as described in the footnote.
Yes
We support the efforts by all project teams to clearly define the implementation and subsequent periodic evaluation time frames – as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC's Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-027-1, we believe that the proposed intervals are sufficient to perform the frequency performance model validations; however they are initiated.
No
Although Ingleside Cogeneration LP agrees with the concept that a base load unit does not need to be verified, it is not sufficient to capture this exception only in Attachment 1 of MOD-027-1. Similar to the exclusions for units with very low capacity factors, the Applicability section must also clearly identify that base loaded units are not subject to MOD-027-1.
We agree with the SDT's position that 80% of generation capacity in each Interconnection should be targeted for validation – not the 100% that some regulatory bodies might prefer. There is a careful balance between the costs to perform the validation and the expected reliability benefit which we expect to gain. We must look for cheaper alternatives for those generators which have a negligible impact on BES performance or serve non-critical load. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-027-1, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities.
No
Ingleside Cogeneration LP has not changed its position that PRC-019-1 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System – and

this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of the BES takes effect.
Yes
We agree that it is appropriate to add a statement to the P-Q and R-X diagrams that they show performance at nominal voltage and frequency levels. We also agree that the SSSL calculation should be based upon a fixed field current value, even if it does not take into account the action of the AVR in automatic mode. It is a far less complex method to use and returns a more conservative value in any case. Ingleside Cogeneration would like to commend the SDT's for holding to its position that there is no need to complicate the analysis by assessing performance under transient conditions or single contingency scenarios. In our view, there is no justification to adding time and effort to an initiative until data shows that it will result in a tangible reliability benefit.
We believe that the project team has taken a positive step in R1.1.1 to establish that Protection Systems must operate before the generator or synchronous condenser sustains damage. This may actually be more sensitive than the SSSL – which is a good, but not perfect, proxy for the point at which components may be harmed. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of PRC-019-1, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
Yes
There is a typo on Row E in Attachment 2: The word "yransformers" should read "transformer".
No
Footnote 5 as written contains requirements that are in addition to Part 2.1.1 as opposed to provide clarification or explain the testing process. We suggest that the requirements in Footnote 5 be put into Part 2.1.1 or its sub-part. We also suggest that the language be made clearer, in particular the use of the word "load" in "load rejection", "load or set point control", and "on load" which is very confusing.

Yes
We agree with the periodicity requirements. We respectfully point out once again that the periodicity criteria are not guidance, they part of Requirement R2 and must be complied with.
Yes
1. In the Applicability Section, 4.2.1, we agree with the change from a 100kV threshold to an MVA based threshold. However, there does not appear to be any technical justification for the first two bullets, i.e. 100 MVA for individual units directly connected to the bulk power system and generating plant with a total of 100 MVA connecting to the bulk power system at a common bus. Why would the first bullet not be 20 MVA and the second bullet not 75 MVA to be consistent with the registration criteria and the thresholds for generators having to comply with MOD-026 and PRC-019? Similar comments on 4.2.2 first bullet, and 4.2.3 first bullet for WECC and ERCOT, respectively. 2. We continue to disagree with Requirement R5 and it Parts R5.1 to R5.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate turbine/governor and Load control or active power/frequency control model, especially if such devices are new for which there are no previous simulations to benchmark with. Part 5.3 stipulates one of the criteria for deeming a model usable. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable.
Yes
Yes
R1 VSL: There is only a SEVERE VSL assigned to Requirement R1, for the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1. This condition does not appear to be consistent with the intent of Requirement R1, which requires the responsible entities to coordinate the voltage regulating system controls, (including In-service limiters and protection functions) with the applicable Facility capabilities and Protection System settings. The parts that follow also prescribe the actions need for verification, not the identification of the existence of the verification

information. Note that the SEVERC VSL for Requirement R2 includes the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years. This condition is almost identical to the SEVERE VSL for R1, except it has a time component associated with the failure. A failure to verify the existence of the coordination specified in Requirement R1 in more than 6 years, despite it might have implemented the verification exercise stipulate din R1, can subject an entity to being found non-compliant twice. We have a serious concern with this.
Individual
S. Tekala
SRP
No
Real Power tests were performed at the same time as Laod Reactive Power testing in the past and plotted on the generator"s capability curves. What would be gained by conducting two separate tests?
Group
SERC Generation Subcommittee
David Thompson (Chair) ; Joe Spencer (SERC staff)
SERC Reliability Corporation
Yes
However, see our response to Question #4.
No
Clarification should be made on applicability. Does this apply only to stand-alone synchronous condensers, or are hydro units, that can be used in condensing mode, also included? Also, we believe that the 20 MVA cut-off rating is too low for this standard. We would suggest that the same threshold used in MOD 26 and 27 (100 MVA), be used. If necessary, the regions can set more restrictive thresholds.
Yes
• Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions (if requested), but this is not included in R1, Attachment 1 or Attachment 2. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination),

some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. • Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. • To accomplish the stated goal of Steady State Model Validation, there needs to be clarity in the definitions for model terms. We have developed a draft set of definitions that is available to the SDT. • Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which provided a process where an engineering review (with associated operating data) should be performed first with testing to be done on a limited basis, if needed, to capture data not covered by an operational review. The SDT could leverage this guide to better understand the approach, which was agreed to by the region's planning and generator operators. This approach should be adopted as an additional method to verification. • Testing may be desirable to identify issues, such as incorrect AVR limiter settings, but there are other methods that also would accomplish those goals. If the goal is operational testing to uncover these types of issues, that should be clarified in the purpose of the standard as opposed to the stated goal of model validation. • Attachment 1, Verification specifications for applicable Facilities, Note 1: We recommend revising the last sentence to state, “The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit’s reactive capability for extreme system conditions. See Note 2.” • Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. • The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. • Attachment 2, Summary of Verification – What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. • Applicability Section – change “bulk power system” to “BES”. • Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or “sister” units should be allowed. • Testing a unit to the limits of its protective function (such as overvoltage) creates the possibility for an unplanned unit trip, particularly problematic on nuclear units.

No comment
No comment
No comment
No comment
No comment
No comment
No comment
Group
SERC Dynamic Review Subcommittee (DRS)
John O'Connor (chair) ; Joe Spencer (SERC staff)
SERC Reliability Corp.
Yes
No
In some cases there is no benefit to require testing of smaller units. The DRS recommends that units with nameplate ratings at or below 100 MVA (consistent with the MOD-027-1) be exempted from testing upon mutual agreement between the GO and Transmission Planner.
Yes
The Transmission Planner is in the best position to determine the impact of the results on long term system reliability. Additionally, the Transmission Planner is often the entity that provides this data to other entities (via the MMWG process) for modeling and simulation purposes.
Yes: • VAR-002-1.1b Requirement R1 states “The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.” However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. The DRS recommends that MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the DRS recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard. • On Attachment 2 Comment Section for Point A, add note that “individual unit values

are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) • On Attachment 1, item 2.6, add sentence stating that “GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.” If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. • On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. • The DRS recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of “sister unit” concept. This will facilitate more consistent unit verifications. • The DRS agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. The DRS recommends that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar changes which impact the reactive testing results. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities.
No comment
No
Regarding the terminology in Attachment 1, “Turbine/governor and load control and active power/frequency control”, should all the “and”s in the Event Triggering Verification column be “or”s? The DRS recommends that this be reviewed for consistency.
No
The DRS sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification.
The DRS found the excerpt below (section 4.2.1 bullet 2)to be confusing, particularly the second sub-bullet below: • For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating); and o Each generating plant or generating Facility consisting of

individual generating units less than 20 MVA (gross nameplate ratings Could the SDT provide some examples of how this would work? Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability.
No comment
No comment
There needs to be a requirement that the GO protection coordinate with the steady state stability limit. We recommend inserting “or reach steady state stability limits” after “equipment” in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions. Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? We recommend that you stay with a 30 day increment. Also in R2 you need a space between “5years”.
Individual
John Seelke
Public Service Enterprise Group (PSEG)
No
In splitting R1 into two requirements, the R2 erroneously refers to “Real Power”; this should be “Reactive Power.” The first sentence in added paragraph Attachment 1 regarding separate testing of Real and Reactive Power testing should be rewritten. The term “Load” as used does not conform to the Glossary definition of “Load,” which is “An end-use device or customer that receives power from the electric system.” The only combined testing on Real and Reactive Power applies to sections 2.1 and 2.2 in Attachment 1 where Real Power is tested. Therefore, the added sentence should be rewritten as follows: “It is intended that Real Power testing in sections 2.1 and 2.2 be performed at the same time as Reactive Power testing; however separate testing is allowed for this standard.”
No
In the Background material on the Comment form for MOD-026-2 and PRC-024-2, the following statement is included for MOD-026-2: “The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO

Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers." If synchronous condensers are not currently addressed in the NERC Registry Criteria, they should not be included in the either MOD-025-2 or PRC-019-1.
No
Transmission Operators should also be provided the data.
We have the following additional concerns: a. The entire section 4.2 has language that includes "directly connected to the bulk power system." The BES is a subset of the BPS per Order 743, and the GVSDT should consult with the SDT for Project 2010-17 – Definition of BES – to develop alternate language that instead refers to the BES. b. We believe that the addition of section 5.3 (Wind Farm Verification) under the "Effective Date" (section 5 in the standard) is both misplaced and confusing. A paragraph should be written in the "Verification specifications for applicable Facilities" section in Attachment 1 that follows paragraph 1 which would clarify for all generators how the percent verification of applicable Facilities in the "Effective Date" section should be calculated. The following is proposed: "1.1 The percent verification for applicable generating Facilities referenced in the "Effective Date" section of the this standard depends upon how the owner of generating units that are 20 MVA or less and that are part of a plant that is larger than 75 MVA in the aggregate choose to address verification. If the owner verifies the aggregate of all units that are less than 20 MVA as a group, then verification must include all of the aggregate units (i.e., a single applicable facility) taking into account the 90% threshold (which is considered "all") for wind turbines or photovoltaic inverters as provided in paragraph 2.1 below. If the owner verifies each unit that is less than 20 MVA on an individual unit basis, then the percent verification for that plant will be calculated on a unit basis. For example, suppose a plant has 5 units that are 20 MVA or less and 4 units that are greater than 20 MVA at a plant that in aggregate is greater than 75 MVA. If the owner chooses to verify each of the 20 MVA or less units individually, there are 9 applicable Facilities at the plant. If the owner chooses to verify the 5 units that are 20 MVA or less as a group, there are 5 applicable Facilities at the plant – one aggregate "Facility" comprised of 5 units that are 20 MVA plus or less plus 4 units that are greater than 20 MVA." c. We are concerned with the requirements in Attachment 1 to perform tests, especially Reactive Power capability tests, with the automatic voltage regulator in service (paragraph 2 under the "Verification specifications for applicable Facilities" section) while maintaining the Transmission Operator's voltage schedule and Reactive Power output (see VAR-002-1.1b, R2). Unless R2 in VAR-002-1.1b is temporarily waived for staged tests, it may be impossible to meet paragraph 2.1 under the "Verification specifications for applicable Facilities" section in Attachment 1 since adjusting the Reactive Power output to verify leading and lagging power limits at maximum Real Power output may cause a violation of the cited VAR-002-1.1b requirement. MOD-025-1 needs to address this issue. RFC's standard MOD-025-RFC-1 addresses the issue in its Attachment 1, paragraph 1.2, which states: "If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the

Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.” d. Paragraph 2 in Attachment 1’s “Verification specifications for applicable Facilities” section has this statement: “Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve.” What is meant by “50 percent of the capability shown on the associated D-curve”? Since the D-curve shows both Real and Reactive Power, would a previously staged test be acceptable if it demonstrated only 50 percent of the maximum Real Power capability per the generator’s D-Curve? e. In Paragraph 2.1 in Attachment 1’s “Verification specifications for applicable Facilities” section, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. RFC’s standard MOD-025-RFC-1 supports this position, since its Attachment 1 states: “Under-excited (leading) Reactive Power capability verification is not required of nuclear units.” This sentence should be added to Paragraph 2.1 in Attachment 1. f. In paragraph 2.2 in Attachment 1’s “Verification specifications for applicable Facilities” section, the second sentence excludes nuclear units (“Units” is inappropriately capitalized in the standard this paragraph) from being required to perform Reactive Power tests in paragraph 2.2. For clarity, we suggest that “nuclear” be included in the wind and photovoltaic exceptions in the first sentence, and that the second sentence be deleted. Paragraph 2.2 would thus read “Verify Reactive Power capability of all applicable Facilities, other than nuclear, wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate.” g. Note 1 in Attachment 1 states: “The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.” If MOD-025-2 data required by Transmission Planners, why wouldn’t the data provided by Generator Owners per MOD-010 for Real and Reactive Power capability be the same data that is developed under MOD-025-1? The SAR for this project stated its purpose: “To ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.
No
Footnote 4, not Footnote 5, addresses the question. Typo in Footnote 4: The word “on” should be deleted in this phrase in the last sentence: “...if the final model is not validated from on load date under...”
No
For ease of reference, we suggest that the three examples in the Background section of the Comment form be incorporated into Attachment 1 or as a separate attachment in the standard.
No
We agree with exempting base load units; however, the term “base load” or “base

loaded" is not referenced in the standard. We could not find the exemption or a definition of "base load" in MOD-027-1.
No
See comments to Question 2 above.
Yes
We have these additional comments: a. Regarding Blackstart Resources, the revision to R4, Part 4.2.4 would only apply to Blackstart Resources that are "material to and designated as part of a Transmission Operator's restoration plan." The Glossary definition of Blackstart Resources already requires them to be part of a Transmission Operator's restoration plan, so that language is redundant and should be removed. Our concern is the requirement that Blackstart Resources also be "material to a Transmission Operator's restoration plan." Who would judge a Blackstart Resource's materiality? The standard leaves this issue open, which is unacceptable. We suggest that Part 4.2.4 be rewritten as follows: "Any generator, regardless of size, that is a Blackstart Resource. b. Typo: in R1, "In-service" (not a Glossary term) should be "in-service."
Group
Bonneville Power Administration
Chris Higgins
Transmission Reliability Program
Yes
Yes
Yes
BPA believes that the applicability from PRC-19-1, 4.1.2 "Transmission Owner that owns synchronous condenser(s)", should also be applied to the applicability of MOD-025-2 with respect to Transmission Owners.
No
BPA believes that partial load rejection is not a suitable test for validating on-line governor response. Most turbine controls, including digital, analog, and mechanical, have different sets of settings for on-line and off-line, and often isolated operations. The settings are quite different, therefore, BPA believes using off-line settings for on-line studies is incorrect. Recording under-frequency events is the preferred approach for governor response validation. BPA recommends removing partial load rejection as an acceptable approach for governor response validation.
Yes
No
BPA believes that the Generator Owner needs to provide evidence that a

generating unit is operated as base loaded. It will be very useful to clarify the “base loaded” terminology as operating with control valves wide open or at the temperature limit, as “base loaded” is often used for different purposes in power plants.
Yes
Yes
Individual
Keira Kazmerski
Xcel Energy
Yes
Yes
Yes
Measure M1 says that the Generator Owner must provide evidence that it has supplied the Transmission Planner with temperature corrected values upon request. Making temperature corrections is not stated in the Requirements or the Attachments. In essence, this is creating an additional requirement within the Measure which is not permissible. If the Drafting Team adds a requirement to perform temperature correction, then Xcel Energy strongly recommends that a Technical Reference be added to provide guidance doing the corrections so there is consistency in how the various Generator Owners perform the calculations.
Yes
The footnote that should be referenced in the question is Footnote 4. Xcel agrees that the control mode differences when using a partial load rejection must be identified.
Yes
Xcel Energy believes Attachment 1 describes more than periodicity and suggests that the first column be titled “Verification Condition” and the second column be titled “Verification Timeline” since several lines are describing how much time following an event or condition is available to complete verification (not the periodicity of the verification).
Yes

For combined cycle steam turbines that operate with turbine control valves wide open it appears that verification is not required based on line 10 of Attachment 1. Is this a correct interpretation, or would it still need to be verified if the combustion turbine(s) supplying energy to the HRSG(s) respond to a frequency disturbance and cause the steam turbine output to respond, albeit with a very long time delay?
Yes
Yes
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
IID
Yes
Not applicable to IID - abstained
Yes
2.3 and 2.4 need clarification whether the real and reactive tests are run separately or concurrently and if that is 1 hour each or 1 hour total.
Abstain. Not applicable to IID.
Abstain. Not applicable to IID.
Abstain. Not applicable to IID.
Abstain. Not applicable to IID.
Yes
Yes
The standard is still difficult to read and determine the applicability to the reliability to the BES. For example, it could not be determined in a first, second, or third reading (with team discussion) whether the standard is suggesting we change the maintenance or operations setting by the manufacturer’s OEM.
Group
Santee Cooper
Terry L. Blackwell
South Carolina Public Service Authority
Yes
No
Clarification should be made on applicability. Does this apply only to stand alone synchronous condensers, or are hydro units that can be used in condensing modes,

also included. Also, we believe that the 20 MVA rating is too low for this standard. We would suggest that the same threshold as used in MOD 26 and 27 (100 MVA) be used. If necessary, the regions can set more restrictive thresholds.
Yes
• Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that's not included in R1, Attachment 1 or Attachment 2. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. • Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. • Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which laid out a process where an engineering review and operating data should be performed 1st and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the regions planning and generator operators. This approach should be adopted as an additional method to verification. • Attachment 1, Periodicity for conducting a new verification: 2) We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. • The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. • Attachment 2, Summary of Verification – What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. • Applicability Section – change "bulk power system" to "BES". • Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or "sister" units should be allowed. • Testing a unit to the limits of its' protective function (such as overvoltage) creates the possibility for an unplanned unit trip, particularly problematic on nuclear units.

Individual
David Youngblood
Luminant Power
Yes
Yes
Yes
Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section 3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2). On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope. Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the simplified one-line diagram ..." Generator Owners can fill in the appropriate quantities at locations A-F. As an

example, on some units values would be input for A, B, and F and NA entered for C, D, and E. For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard.
Yes
Yes
No
Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and specifically include the exemption that excludes units that are base loaded in the standard. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3).
Yes
No
Luminant disagrees with the need to illustrate coordination of the phase distance relay with AVR controls. The sample R-X diagram does not indicate how the relay is coordinated with field forcing capability. Since this function is covered in the generator loadability standard currently under development, Luminant recommends that this function be removed from the R-X diagram.
Luminant recommends in Requirement R1 that the coordination with Protection System be modified to reference the “applicable Protection System devices as referenced in Section G”. As written, Protection System is all inclusive and would require verification of settings beyond the scope of this standard.
Individual
Joe Petaski
Manitoba Hydro
Yes
Yes
Yes
Manitoba Hydro is voting negative for the following reasons: (1) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. (2) - Transformer Tap Settings - Under “Summary of Verification”, transformer tap settings should be replaced by transformer voltage

ratio as tap settings on their own do not provide sufficient information. (3) - Effective Date 5.3 - 5.3 is too specific and should not be a separate sub-section in the Effective Date section. 5.3 should be removed and replaced with a general note explaining how verification percentages should be calculated for wind farms. Suggested wording - "Note - With respect to wind farm sites, the level of completion of verification shall be calculated on the basis of the number of sites, rather than the number of turbines at each site." (4) - Temperature Range - Manitoba Hydro suggests that the GO should be required to provide a unit's performance in a reasonable temperature range as specified by the Transmission Planner. (5) - Consistency in reference to capability curve - a unit's capability curve is referred to as a D-curve, D-Curve, thermal capability curve, Thermal Capability Curve, and MVAR capability curve in the standard. References to the curve should be consistent. We suggest the curve be referred to as 'Generator Capability Curve'. (6) - Notes 2 and 3 - Notes 2 and 3 should be removed from the standard as they do not seem to be required for compliance purposes and their inclusion creates a lack of clarity. (7) - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to all standards in this project.
Yes
No
See comment (3) provided in Question 8.
No
See comment (2) in Question 8.
Manitoba Hydro is voting negative for the following reasons: (1) - Verification of identical units - The standard should address the verification of identical sister units. There is no reason to test two identical units. (2) - 'Base Loaded' - The drafting team should clarify what is meant by 'base loaded'. Manitoba Hydro believes that it is important to verify base loaded units. (3) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.
Yes
Yes
Manitoba Hydro suggests that example curves be provided for variable generation plants.
Manitoba Hydro is voting negative for the following reason: (1) - Implementation

time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.
Individual
Jack Stamper
Public Utility District No. 1 of Clark County
Yes
Yes
Yes
MOD-025 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60% and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-025. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
No
My Utility's only generator is a combustion turbine with a steam turbine and generator all attached to one shaft. Any load rejection event decreases the life of the components and should be avoided unless absolutely necessary. While partial load rejection testing may not significantly impact other forms of generation (i.e. hydro) the GVSDT needs to exercise caution in using simulated load rejection as a means of testing generator response.
Yes
Yes
I agree with the concept but have been unable to find where in the proposed standard such an exemption is described. My Utility has one generator that is always operated as a baseloaded unit.
MOD-027 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 25%, 50%, and 75% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-027. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Yes
Yes

PRC-019 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60%, and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with PRC-019. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
Yes
Yes
Under MOD-025 Attachment 1, “Periodicity for conducting a new verification”, Item 2, LADWP believes that the term “operation data” needs to be further clarified. Please provide the methodology and list of data types that qualify as meeting the requirement for verification using historical operational data.
Yes
No
The criteria “Consideration for Early Compliance” seems to parallel the language for the draft of MOD-026-1 which deleted the redundant statement of, “The Generator Owner has an existing verified model that is compliant with the requirements of this standards.” It is understood that the applicable entity is compliant if it meets this criteria.
Yes
Provide examples for methodology and data meeting the requirement for verification using historical operational data in accordance MOD-027-1 Requirement R2; 2.1.1 for frequency excursion from a system disturbance. In regards to: 4. “Applicability” 4.2.2 Generating units connected to the Western Interconnection with the following characteristics: • Individual generating unit greater than 75 MVA This criteria seems to conflict with the Applicability requirement of MOD-025-2; 4.2.1, Individual generating unit greater than 20 MVA. Why are the generating unit MVA criteria different across the MOD Standards?
Yes
Yes

In regards to PRC-019-1, Attachment 1- Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency, since different entities might have different standards in their Generator Protection System Standards for their generating units, it is not clear if they need to superimpose only some specific protection curves or if they are going to be expected to provide the curves for all the equipment protection wired into their generator protection systems. Additionally, some protection equipment from different OEM's has time-dependent characteristics such as OELs. Since the reactive capability curve represents steady-state limits, representing OEL characteristics on the RCC is not completely straightforward. When providing examples, have you consider the economic impact on implementing those examples?
Group
Dominion- NERC Compliance Policy
Mike Garton
Dominion
Yes
Dominion agrees with splitting Requirement R1; but notes that Requirement R2 should be changed from "Real Power Capability" to "Reactive Power Capability." Additionally, Requirement R3 should be changed from "Real Power Capability" to "Reactive Power Capability."
Yes
Yes
Dominion points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2. Additionally, on Attachment 1 at 2.2, "Applicable Facilities" should be changed to "applicable Facilities" to be consistent with usage elsewhere in the standard. * VSL's for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33. * VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from "more than 12 calendar months but less than or equal to 13 calendar months" to "greater than 15 calendar months." * Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word "reactive" be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." * Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. * Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient

conditions, if applicable, at the end of the verification period that the Generator Owner requires..."
No
Footnotes should not contain requirements. If necessary, then they should be moved into the requirements section (i.e. Footnote 4). Against giving the option of purposefully causing system disturbance (i.e. load rejection). It is unclear how this would benefit the reliability of the BES compared to the two other data collection methods available.
Yes
Yes
Dominion agrees that base loaded units should be exempted; however, that exemption is not clearly articulated in the standard. Dominion recommends that a base load exemption statement be added to the “Applicability” section of the standard.
Yes
Dominion agrees, but points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2.
No
Section G provides additional clarity. However, the Purpose, R1.1 and Section G do no fully align. It should be made clear that all generator protection system devices aren’t applicable.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
Requirements R1.2 and R2.2 have data submittal dates for Real and Reactive Power verification values. The required timeframe of “90 calendar days” needs to be clarified when using historical operating data. For example, if a date of 180 days ago is selected for the verification, how can the data be required within 90 calendar days? The due date for a verification using historical data does not seem very meaningful.
Yes
Yes
a. In Requirement R2.1, the capability is to be verified at the “normal expected maximum Real Power” value. Since the verification cannot always be done in ideal conditions, there needs to be more flexibility in acceptable MW values to account for non-ideal conditions, such as wet coal, for example. A value of “greater than 90

percent of normal expected maximum Real Power" is recommended instead of "normal expected maximum Real Power". b. Also in Requirement R2.1, the requirement for wind turbines is to have 90 percent of the turbines on-line for the verification. We support having a requirement of 50 percent of rated maximum Real Power, as specified in the ReliabilityFirst regional standard, MOD-025-RFC-01. Using a more attainable requirement for wind turbines will also eliminate the need for re-testing. The standard should have more flexibility for intermittent resources like wind. c. In Requirement R2.2, the capability is to be verified at the "minimum Real Power output". It may be difficult to operate the unit in a reliable and stable manner exactly at the "minimum" MW value. We suggest allowing more flexibility when verifying at the minimum Real Power value. We propose to allow a range from the minimum Real Power value to the minimum value increased by 10 percent of the rated maximum Real Power. For example, if the maximum Real Power of a generator is 200 MW and the minimum Real Power is 50 MW, the verification for Reactive Power at minimum Real Power could be done anywhere between 50 MW and 70 MW Real Power. This or some other means of providing greater flexibility at the lower end would especially be needed for coal units. d. In Measure M1, there is a reference to providing values corrected for ambient conditions, if requested. There is no mention of this in the Requirements section. This wording should be deleted, or else any such requirement should be specifically included in the Requirements section. e. In Attachment 1, 3.1, the values of Real and Reactive Power are to be recorded "at the end of the verification period." It is suggested that the average (mean) values of these quantities over the verification period should be recorded, rather than simply the last value. f. In Attachment 2, there is a requirement to provide net values at the high-voltage side of the GSU (Point F). This requirement should be deleted. The values for Gross, Auxiliary, and calculated low-side net are sufficient to document the verification. In addition, the required metering at this location may not be available. We have conducted field verifications for five years now, and the low-side values for MW and MVAR have been quite adequate.
No
There is not nearly enough confidence that governor testing on a unit connected to the system is safe or desirable, whether it is partial load testing or a change in the speed governor reference. Footnote 4 seems to make the value of any online testing very questionable. NERC should work with turbine-generator and controls suppliers (OEM's) to validate the concept of online testing of governor controls. The use of recorded data during frequency excursions also requires more information on what would constitute adequate data. In summary, more work on such a requirement for online testing is needed, as well as collaboration with equipment suppliers.
No
When it takes five pages to describe the periodicity requirements, the standard is overly complicated.
No
We agree with the concept of an exemption for units that are running most of the time. It is not at all clear where this exemption exists in the standard. Does this

mean that a "base-load unit" never requires a model verification? If not, it is unclear what purpose this exemption serves.
a. In Section 3 "Purpose", reference is made to Bulk Electric System (BES) reliability. Then, in Section 4.2, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. b. In Section 4.2 Applicability, Footnote 2, the reference to startup or standby units should have further detail since these terms are not defined by NERC, or simply remove this footnote. c. In Requirement R1, instead of the Transmission Planner (TP) providing "instructions" on how the Generator Owner (GO) can obtain necessary models and associated information, the standard should require the TP to simply "provide" the model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. In addition, the TP should provide the OEM model data sheets or other data supporting the current in-use models in the dynamics database. d. In R2.1.1, the GO is required to provide documentation comparing the turbine/governor model response to the recorded response for a frequency excursion while online, or a change in reference while online, or a partial load rejection test. Since the GO usually does not have the capability to run such dynamic studies, it is not clear how will it obtain the "model response" for comparing to the recorded response. When there is more collaboration between NERC, Generator Owners and OEM's on the methods for online governor verification (see Question 5 response above), only then should there be any requirement that the GO "provide the recorded response for a frequency excursion". As presently written, R2.1.1. can only be required of the TP. Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the data required in R2.1.1. This standard is too far ahead of the existing capabilities for verifying these controls. More work is needed, and it is strongly suggested to bring OEM's into the process to enable the development of a useful standard. e. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the business need to develop these equivalent models like the TP does for system modeling. This requirement would demand resources in return for no increase in reliability. The requirement should allow the GO the ability to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate model. f. It is not clear how this standard relates to variable resources such as wind farm. It is suggested that these generating sources should be specifically

excluded from the Applicability.
No
The Applicability section in 4.2 refers to generators being connected to the “bulk power system”, or BPS. The reference should be to the Bulk Electric System (BES), which is defined by NERC. The BPS is not a defined term in the NERC Glossary, and using this term is extremely confusing and possibly misleading. The GVSDT’s use of the term BPS, here and in several other standards, opens the door for applying NERC standards to generating units which are connected to the system at voltages below 100 kv. The applicability should solely be to generating units of the MVA size required for registration and connected to the BES at 100 kv or higher, and to those generators which are blackstart resources.
Yes
It is not clear how the field current limiters or trip settings are plotted on the P-Q diagram, since these parameters are dc field amps.
a. In Requirement R1.1.1 , the requirement to verify that Protection System devices are set to “operate before conditions cause damage to equipment” is not attainable and should be revised or eliminated. The best possible settings cannot guarantee that equipment will not be damaged. The best that can be expected is for protection settings to decrease the risk of damage, or to limit the extent of damage if it occurs. b. In Requirement R1.1.2, the requirement to make sure that the limiters and protection settings are applied to in-service equipment is not necessary, and should be removed. It can be expected that professionals in the electric power industry are aware of the need to verify that the settings on in-service equipment are proper. Though errors may occur, this is an obvious aspect of good utility practice and responsible care of assets. Therefore, there is no need for a regulatory requirement. In fact no regulation is able to totally prevent human error. Measure M1 also requires a similar change in this regard. c. In Section F Associated Documents, better references would be the following IEEE Power System Relaying Committee documents: 1. “IEEE C37.102-2006 IEEE Guide for AC Generator Protection”, and 2. “Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring generator verification of both Real and Reactive Power on a continent-wide level. This standard will also remove the Regional “fill in the blank” obligation to have Regional generator verification requirements. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this

standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. b. ReliabilityFirst requests clarification on why the term “Bulk Power System” is used rather than “Bulk Electric System.” ReliabilityFirst interprets, that by using the term “Bulk Power System”, units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. 2. Measure M1 a. The term "if requested" needs to be removed from the fourth line of Measure M1. The condition of “when requested” is not listed in Requirement R1. 3. VSL Requirement R1 a. The VSLs under the first “OR” statement should reference Attachment 1. This same language should be included in the VSLs for Requirements R2 and R3 as well. Here is an example of a “lower” VSL: “The Generator Owner verified the Real Power capability, per Attachment 1, and submitted the data but was missing 1 to 33 percent of the data. b. The Moderate VSL under the first “OR” statement, should be changed to state “…missing 34 to 66 percent of the data.” As currently stated, missing 33% would fall under both the Lower and Moderate VSL category.
ReliabilityFirst abstains and offers the following comments for consideration: 1. Facilities Section 4.2 a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. b. ReliabilityFirst requests clarification on why the term “Bulk Power System” is used rather than “Bulk Electric System.” ReliabilityFirst interprets, that by using the term “Bulk Power System”, units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. 2. Requirement R1 a. For the purposes of NERC standards, “bullets points” are to be considered “OR” statements. ReliabilityFirst believes all the “bullets points” in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) 3. Requirement R4 a. ReliabilityFirst seeks clarification on the rationale/justification for the 180 calendar day time period for the Generator Owner to provide revised model data to the Transmission Planner? ReliabilityFirst believes this data should be provided within 90 calendar days consistent with other requirements in the standard (which require 90 calendar day submittals). 4. Proposed new Requirement R6 a. ReliabilityFirst recommends the inclusion of a new Requirement R6 which would be a follow-up to Requirement R5. Requirement R5 requires the Transmission Planner to notify the Generator Owner if the model information is not useable (along with the technical description) but there is no corresponding requirement for the Generator Owner to make the model “useable” and submit it back to the Transmission Planner. ReliabilityFirst believes the feedback loop needs to be closed and a new Requirement R6 should be included. 5. VSLs – General format a. A number of VSLs use a parenthetical indicating the associated requirement number, some VSLs use the language “per R1”, and other VSLs do not indicate the requirement number at all. ReliabilityFirst suggest using one consistent style/format and apply to all VSLs. b. For consistency when referencing subparts,

the VSLs should have the same nomenclature. For example, the VSL for R2 states “Requirement R2, Subparts 2.1.1, through 2.1.5.” while the VSL for R5 states “Requirement R5, Parts 5.1 through 5.3.” ReliabilityFirst suggest using the following format: “Requirement R1, Part 1.X”. 6. VSL for Requirement R2 a. ReliabilityFirst recommends the language be consistent across all four sets of VSLs. For example the Lower VSL states “provided its verified model(s)” while the Severe VSL states “provided its verified turbine/governor and load control and active power/frequency control model(s).” ReliabilityFirst suggests using the language as stated in the Severe VSL for the other three VSLs. b. There is no reference in the VSLs associated with Requirement R2, Part 2.2. ReliabilityFirst recommends adding a set of VSLs to cover a possible non-compliance with Requirement R2, Part 2.2.
ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. b. ReliabilityFirst requests clarification on why the term “Bulk Power System” is used rather than “Bulk Electric System.” ReliabilityFirst interprets, that by using the term “Bulk Power System”, units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES 2. Requirement R2 a. ReliabilityFirst recommends removing the following language from Requirement R2: “that are expected to affect this coordination.” The term “expected” is ambiguous and is hard to measure. b. ReliabilityFirst recommends adding the phrase “with applicable Facilities” after the opening phase of, “Each Generator Owner and Transmission Owner.” The addition of this language will be consistent with the language in Requirement R1. 3. Measure M1 a. The language in Measure M1 is set up more like a requirement /RSAW rather than a Measure. Measures should be set up to provide identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Furthermore, the Measure should not introduce new concepts or requirements. ReliabilityFirst recommends the following for consideration: “Each Generator Owner and Transmission Owner with applicable Facilities will have evidence that it coordinated the voltage regulating system with the applicable Facility capabilities and Protection System settings as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.” 4. Reference Section a. ReliabilityFirst recommends removing the “Examples of Coordination” from the standard since they are simply guidance (as stated in the note - This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions). Examples would be more appropriately housed within an associated whitepaper, FAQ, guidance document, etc. and should not be housed within a NERC Reliability Standard. 5.

VSLs and associated Requirements a. When timeframes are referenced within the VSLs (and associated Requirements), ReliabilityFirst recommends strictly using a month format (e.g. 60 months) instead of a year/month format. This would be consistent with various other NERC Reliability Standards.
Individual
Kirit Shah
Ameren
Yes
Yes
Yes
(1)R1 and R2 require verification of the Real and Reactive Power capability of Applicable Facilities using Attachment 1. Attachment 1 ONLY allows verification by: (a) staged verification, or (b) verification using operational data. We suggest that the GVSDT add an additional option allowing engineering analysis verification. (2) Replace the term “Bulk Power System” with “Bulk Electric System” in Applicability section, items 4.2.1, 4.2.2, and 4.2.3. The use of the term “bulk power system” throughout Section 4.2 Facilities should be replaced with the term “Bulk Electric System (BES)”. The use of the term bulk power system, which is not defined in the NERC Glossary, is problematic in determining which generating units and plants must comply with this new Standard. (3)In Note 1 of Attachment 1 to the draft MOD-025-2 standard, it is recognized that, at a given time, one or more generating units under test may not be able to reach full reactive capability as expected based on a review of the unit(s) thermal capability curve due to prevailing transmission system conditions. It is further recognized that the verified reactive power values obtained via testing will likely not agree with the reactive capability as used in model data submitted in compliance with Reliability Standard MOD-010. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed. As presently written, MOD-025 Attachment 1 allows only staged testing of the generating units or use of operational data. (4)The Attachment 1, Note 1 refers to the following. (a) The verification values produced by compliance with this new Standard. (b) The manufacturer’s D-curve values. (c) The Transmission Planner’s database values. (d) The MOD-010 values. Such multiple set of values appear to be in conflict with the purpose of the standard which is, “…ensure accurate information on generator gross and net Real and Reactive Power capability…is available for planning models used to assess Bulk Electric System (BES) reliability”? In this regard we fail to see a need for verification as suggested in this standard. We request the GVSDT to clarify if our interpretation is incorrect. (5)The middle paragraph on page 1 of Attachment 1 requires that any generator that can be operated in both generation mode and synchronous condenser mode must be verified in EACH mode of operation – generation and synchronous

condenser. We believe there should be exemptions for small hydro units which in frequently operate in the synchronous condenser mode. (6) Applicable size for the generating facilities in MOD-025-2, MOD-026-1, and MOD-027-1 should be consistent, which is a minimum size of 100 MVA. (7) Rather than a constant 5 year verification cycle, we suggest that the GVSDT consider a 10 year verification cycle with annual confirmation of the most recent verification. The first cycle could make use of the latest MOD-024-1 and MOD-025-1 values. (8) An option should be added for plants with more than one identical unit (sister units) allowing testing for one unit in place of all the identical units. Each cycle the GO should test a different sister unit until all have been tested. (9) Likewise, if MOD-010 data is still required, its requirements should be incorporated into this Standard in the next draft. (10) In the Implementation Plan, with the effective date of this standard, the previous version of related standards should be retired such as MOD-010. (11)Violation Severity Levels - R1 Moderate should be 34 to 66 percent. (12)In the R1 Severe Violation Severity Level, the last paragraph has same time frame shown as the R1 Lower VSL (more than 12 calendar months but less than or equal to 13 calendar months). (13)Violation Severity Levels - R2 Severe last paragraph has same time frame as R2 Lower – similar situation to comment above. (14)Violation Severity Levels - R3 Severe last paragraph has same time frame as R3 Lower – similar situation to comment above.
No
We agree with the inclusion of an additional option, but find this footnote to be a concern. The footnote is too vague and provides no guidance on an appropriate model, the acceptable quantitative differences or any way for a GO to benchmark the adequacy of its verification.
No
(1)We believe that any testing or verification required by MOD-012, MOD-013, MOD-026 and MOD-027 should have the same periodicity so that all required tasks can be performed in parallel. Note that earlier we have suggested a 10 year cycle. (2)We believe Attachment 1, row 4 is intended to allow “sister unit” testing so plants with multiple identical units are not required to verify each identical unit during each verification cycle. If this is the case, please clarify this option more clearly in the Attachment or the Standard.
No
We are in agreement with the exemption in the statement, but unclear where it is provided in either the Requirements or Attachment 1. Please clarify how this option is allowed.
(1) Footnote 4: “...validated from on load data...” For clarification, please consider that this be changed to read “...validated from on-line unit data...”. (2) Regarding the title of Attachment 1 “Turbine/Governor and Load Control and Active Power/Frequency Control Model Periodicity” – should the ‘and’ before ‘Active Power/Frequency Control’ be changed to an ‘or’ to be consistent with the title of the draft Standard? Similarly, the phrase “turbine/governor and load control and active power/frequency control” appears in several places in the VSL table. Should the ‘and’ before ‘active power/frequency control” be changed to ‘or’ in these instances for consistency? (3) Violation Severity Levels - R5 Moderate: There is

conflict here because failure to respond within 150 days automatically puts one in the High category. (4) There is a concern that different effective dates between the MOD-26 and MOD-27 standards will be burdensome for the Transmission Planner to track and analyze model updates. The Transmission Planner would prefer to receive the exciter and governor models updates for a specific unit at the same time. (5) Replace “Bulk Power System” with “Bulk Electric System” In the Applicability section, items 4.2.1, 4.2.2, and 4.2.3. (6) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website. (7) R2 and R2.1 require each GO to provide for each generator a “…verified turbine/governor and load control…model…” The GVSDT should provide guidance on how to quantitatively determine when a model is verified for each unit.
Yes
The VRF and VSL need to be modified to put the significance to BES reliability in proper perspective; refer to our comments in response to question 11.
Yes
Please clarify that R2 applies to Generating / synch condenser coordination as stated in A.3 in order to avoid confusion with the GO-TO Protection System coordination being addressed under Project 2007-06 and its proposed PRC-027-1. (2) We believe that R2 is confusing as written. Please restate with subparts to clarify. Insert ‘latter of’ before ‘identification or implementation’ to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. For a given generator several changes may be identified at different times and then implemented during a common major overhaul or maintenance outage. A ten year periodic coordination review is sufficient if no other change has triggered a review; redoing a study more often than needed distracts valuable resources for other activities more important to BES reliability. We propose: (R2) Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1: (2.1) At least once every ten years; or (2.2) Within 90 calendar days following the latter of identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following … (3) From our perspective High VRF is not justified. We suggest changing to Medium risk which in our opinion is a stretch for the following reasons. (3.1) PRC019 capability, limiters, and protection apply to a specific Element, one generator at a time, and if are not coordinated that single generator may be removed from service or may be damaged. But the loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures. If the generator trips because of loss of field, BES voltage state will actually improve. Furthermore, many generators have very few operating hours per year and pose little risk to the BES. High Risk requirement is not met. (3.2) PRC019 is not comparable to either PRC012 or PRC023. (3.2.1) Loss of a single generator differs from SPS in PRC-012 which trips more than one Element. (3.2.2) The vast majority of the generators under PRC019 have much less capability than the Elements under PRC-023 which are either >200kV or critical BES lines and transformers in PRC-023 which are major Elements. FERC Guideline 3 is not met. (3.3) In an emergency condition, lack of intended coordination could affect the electrical state if many generators

tripped. This supports Medium not High for FERC Guideline 4. (4) VSL is misaligned with respect to this standard Facilities and Implementation. (4.1) Please add a % of Facilities threshold in R1 to better match the risk to BES reliability. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. (4.1.1) For R1, we suggest thresholds of 5% of the entities Facilities for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe VSL. (4.2) For R2, please replace the time-based (days late) with % of MWh (or MVar-hours for synchronous condensers) during the period of violation to more properly account for aggregate impact. For example, (4.2.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.' (4.2.2) Moderate VSL becomes '…more than 5% and less than 10%' (4.2.3) High VSL becomes '…more than 10% and less than 15%' (4.2.4) Severe VSL becomes '… more than 15%' (5) VRF and VSL need to be applied commensurate with BES reliability risk. (5.1) We believe that in this standard, VRF High and VSL Severe is not justified as drafted, and likely to lead to the unintended consequence of disabling limiters and protection to avoid compliance burden. (5.1.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.' (5.1.2) Moderate VSL becomes '…more than 5% and less than 10%' (5.1.3) High VSL becomes '…more than 10% and less than 15%' (5.1.4) Severe VSL becomes '… more than 15%' (6) Violation Severity Level R2: The increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Also in R2 you need a space between "5years". (7) There is no mention of working with the Transmission Planner anywhere in the standard. The TP will be the entity that determines the Steady State Stability Limit. (8) Please replace "Bulk Power System" with "Bulk Electric System" in numerous places. (9) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website..
Individual
Kathleen Goodman
ISO New England Inc.
No
Attachment 1 does not require a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% for up to 12 months. This is too long a period for a generator to be providing less than expected power output.
Yes
No
We feel that the Reliability Coordinator is the appropriate entity to receive this data. In our area a number of entities are registered as Transmission Planners, to avoid confusion this data should be submitted to a single entity who will then

distribute the data.
This testing will be difficult to stage due to the four point reactive power testing. The power system will have to be reconfigured in many cases to allow for the changes in generator reactive output For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are “on-line”. For reactive testing, would this be better stated as 90% of the plant’s capability available, considering some wind turbines maybe be able to produce/absorb reactive power with no real power production, or does on-line just imply that the turbine breaker is closed and no requirement for real power production? In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power connected at the high-side of the generator step-up transformer (point D) and Aux or Station Service Real Power connected at other points of interconnection (point E) with no discussion? Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)?
Yes
Yes
No
Base loaded units could provide governor response for over-frequency events and should have verified models for this event.
We feel that some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical.
Yes
Yes
Individual
Mark B Thompson
Alberta Electric System Operator
1. In section 4.2, the AESO considers the existing applicability for reactive power verification to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a

change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect, or some qualifying language needs to be added.
No
The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units.
1. In section 4.2.2, the AESO considers the existing applicability for model validation to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. 3. Requirement R4, as written it appears owners of generating units that plan to change out the governor are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change.
Individual
Darryl Curtis
Oncor Electric Delivery Company
Yes
Yes
No
In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.
No
Yes
Yes
Yes

No
Yes
Yes
No
Individual
Cristina Papuc
TransAlta Centralia Generation LLC
No
Do not agree to Attachment 1 item 2.2 and 2.3. Refer comments below: 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Typically, the maximum overexcited and under-excited reactive capability is tested at the Rated or full Real Power output of generator, not at the minimum Real Power output of generator. 2.3. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour. Please verify the reason for a minimum of one continuous hour.
No
In some cases, the data at the interconnection point (such as the high side of generator step-up transformer) may not come directly from GO as the measuring instrumentation may not be owned by the GO
The Transmission Operator (System Operator) should be included as an applicable functional entity since the Reactive Power verification test will to be coordinated by Transmission Operator (System Operator). There should be a requirement assigned to TOP for such coordination.
Yes
Yes
Yes
Yes
Yes
R2. Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or

within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, Please verify the reason for “at least once every five years”. If the existing practice (such as 5 years testing in the WECC region) shows that for those generators without changing any associated equipment the models do not change more than 5 years, it is recommended the duration be longer than 5 years.
Group
Tacoma Power
Chang Choi
Tacoma Power
Yes
None
Yes
None
Yes
None
None
Yes
The question above should have referenced footnote 4.
No
Attachment 1, especially the column titled “Verification Periodicity” is difficult to interpret. For example, for the “Event Triggering Verification” row titled “Initial verification for a new applicable unit…” the periodicity is stated as “Record unit Real Power response to first frequency excursion…. OR record unit Real Power response for….reference change….no more than 365 calendar days from the commissioning date”. This language implies that there is no stated periodicity applied if the generator owner elects the frequency excursion event option. Rather the generator owner must interpret that such an event has occurred, even if it happens 15 years later, and then has 365 calendar days to verify the model. The periodicity as applied to existing fleet and new/changed fleet should be made easier to interpret.
No
A text search of all three standards did not return the term “base loaded”. Tacoma is not aware of an industry standard definition for the term “base loaded”. If a unit is typically left at static output to meet base system load requirements it may likely still have droop as part of its governing system. As such, it would still be expected to respond to system frequency excursions.
Requirement R2.1.5. It may be difficult to model the characteristics of outer loop controls (such as operator set point controls and load control) within the typical industry-standard modeling software parameters.
Yes
None
Yes
None

What if, during the Implementation Plan, it is discovered that coordination does not exist, but the situation is resolved before the effective dates contained in the Implementation Plan? Would this constitute a violation of PRC-019-1? The Implementation Plan uses the phrase "…shall have verified…" R1.1.1 would require that "…the Protection System is set to operate before conditions cause damage to equipment…" Yet, the NOTE under Section G (Reference) states that "this standard does not require the installation or activation of any of the above limiter or protection functions." The latter statement could be construed (in the extreme case) to permit little or no protection functions, but this would appear to violate R1.1.1. Clarification is requested, as these two portions of the standard appear to conflict. Under R2, is the 5-year interval (a) 5 calendar years or (b) closer to 1825 calendar days? R2 requires that entities "…verify the existence of the coordination identified in Requirement R1…within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following…" Protection System component changes is listed. If a component is replaced in-kind, is it actually required to verify the existence of the coordination identified in both Requirement R1.1.1 and R1.1.2, or just R1.1.2? Or, would this change be N/A to PRC-019-1 because it is not "…expected to affect this coordination…"? Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity.
Individual
Dennis Sismaet
Seattle City Light
No
Attachment 1 "Periodicity for conducting a new verification:" Frequency of tests should correlate better with MOD-026 and MOD-027, which is once every 10 years.
Yes
Attachment 1 "Verification specifications for applicable Facilities:" section 2.3: It will be difficult to test at maximum power for one continuous hour at some plants due to operating restrictions regarding water flow or other factors.
No
It appears but is unclear if a partial load rejection test is acceptable. The unit on-line test is difficult to capture without functioning Digital Fault Recorders, which are not available at all plants. Seattle City Light requires a clarification in the text if on-line testing required or is a partial load rejection test allowed.
No

Once every ten years seems reasonable with load rejection testing, but it is unclear if frequency excursion modeling is required during operation.
Yes
On-line monitoring is required to meet this draft Standard but is not yet available at all many generating plants. For the monitoring proposed, it will requires very high resolution Digital Fault Recorders that currently are not available nor required (side note: as of right now in WECC existing generating plants below 1500 MW are not required to have DFRs, and many or most do not). The cost vs. benefit of such a demand should be reviewed and clarified.
Yes
Yes
New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Individual
Russell A. Noble
Cowlitz County PUD
Yes
Yes
Yes
Cowlitz understands the SDT must comply with FERC directive in Paragraph 1321. However, Cowlitz disagrees that requiring verification every five years will not be too burdensome to the GO. Cowlitz is not confident that verification will be possible with operational data, and will be forced to verify via staged verification for at least two of the test points. We suggest that staged verification for four test points be required every 10 years with operational verification within 10% of at least one test point from the last staged verification being made no greater than 5 years after the staged verification. Should all four staged test points be confirmed via operational verification within 5 years of the last staged verification, then staged verification will reset to 10 years. If operational verification can't be provided within 5 years of the last staged verification, then one point must be verified via staged verification 5 years after the last full staged verification (all 4 points). Cowlitz also disagrees with the generation applicability set at 20 MVA. This is arbitrary; FERC made no

mandate in this regard and in fact shared a “concern with several commenters that such a requirement for all [Registered] generators may not be necessary.” Cowlitz respectfully points out that it appears the SDT made no effort at all to determine true Reliability impact. Drafting Reliability requirements with no Reliability return must be avoided. SDT statements that simply state “the effort is not considered to be costly or burdensome” is not acceptable as it only offers an opinion without substantiating evidence.
Cowlitz respectfully asks that the Standard number be referenced in multiple standard comment forms. Did you mean footnote 4? As a small GO, Cowlitz would have to hire a consultant to comment on this question, and therefore must defer to larger GO’s who have the appropriate subject matter experts available.
Cowlitz could not find the guidance.
Cowlitz could not find any mention of “base loaded unit” in MOD-027-1.
In the applicability section 4.2.2, second bullet states “comprised consisting.” Cowlitz suggests deleting one of these words. Cowlitz also struggles with why the generation applicability is set at 75 MVA for the Western Interconnection. Is the SDT trying to encompass 80% of all Registered generation? Cowlitz abstains as it appears this standard may require information that may not be possible to obtain, but can’t offer technical basis at this time and will defer to commenters better equipped to answer.
No
Cowlitz believes 20MVA is meant to catch users who may adversely affect the BES, such as via a faulty BES Protection System a small generator may own. The registry criteria should not endeavor to identify generation that is necessary for the support of the BES. Cowlitz feels this standard applicability conflicts with Phase 2 of Project 2010-17, Definition of Bulk Electric System. This standard should only apply to BES generation which currently is poorly defined. If this standard is needed urgently to cover a Reliability gap, Cowlitz would suggest an arbitrary 200 MVA applicability be established and a phase 2 SAR be established to adjust the standard to apply to BES generation after completion of Project 2010-17. Cowlitz commends and thanks the SDT in addressing this question.
Yes
Group
Southern Company
Antonio Grayson
Operations Compliance
Yes
a) The method of reactive power capability determination described in "Note 2" of Attachment 1 should be included as an allowable third (3rd) method of reactive power capability verification. (as an alternative to using operational data or staged testing) b) Any verification specifications listed on Attachment 1 that merely repeat the line items of data requirments shown on Attachment 2 should be eliminated - they are not necessary in both locations.

No
a) The applicability threshold is too small. Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to individual unit size of 100 MVA for the Eastern Interconnection. b) We feel that machines able to run either as a synchronous condenser as well as a synchronous generator need only be validated in generator mode. It is unclear if the requirement for synchronous condensers is for machines with a single mode of operation. c) The individual unit size criteron value should equal the gross aggregate plant/ Facility threshold value.
Yes
1) Applicability, Section 4: Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to focus on standard requirements that have significant impacts on system reliability, and including smaller units (without demonstrating their criticality to the system) seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where relability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. 2) Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 3) Attachment 1, Verification specifications for applicable Facilities, Item 2: Delete the requirements for mandatory “staged testing”. Allow staged testing as an alternative. There is no industry consensus that staged testing is superior or achieves better reliability results for modeling purposes than the use of operational data coupled with a proper engineering study. A staged test performed every 5 years in our experience is not a substitute for proper planning, proper implementation of limiter and protection settings, equipment monitoring, unit data trending, and operational awareness and identification of plant equipment problems that could impact the MW or MVAR capabilities of a unit. Staged testing alone typically does not prove a unit’s reactive capability, because the unit’s true reactive limit cannot be reached due to transmission voltage and reliability constraints during the test period. We believe staged testing alone cannot accomplish the reliability purpose of this standard. While staged testing can identify problems such as incorrect AVR limiter/protection settings or non-optimum transformer tap settings, these problems can be identified and corrected without staged on-line testing. 4) Attachment 1, Verification specifications for applicable Facilities, Item 3.4: This increases the complexity and reporting requirements for compliance. In practice, we believe the margins of error in transmission models do not require this level of detail and accuracy for periodic verification of unit MW capability. For the purposes

of this standard, we believe recording of the MW for typical normal summer or winter conditions is sufficient. If a unit's MW capability is in question, TOP-002-2b R13 already has provisions for performing a more detailed verification, including ambient and water temperature conditions, at the request of the BA or TOP. 5) Attachment 1, Verification specifications for applicable Facilities, Note 1: Revise the last sentence to state, "The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2." 6) Please add page numbers to every page of the standard. 7) Attachment 2, Summary of Verification – What is the purpose for the fifth bullet? MVARs are a function of both the generator voltage and the system voltage. Thus, how to adjust the recorded Mvar values to rated generator voltage is not clear, is subject to dispute, and implies that engineering analysis is required to determine this result. 8) Attachment 2 Remarks – It is unlikely that the generator capability curve will be reached either during a lagging VAR test or during collection of operational data when a GSU tap has been set to support the normal system voltage ranges. The generator should be able to support the normal system voltage range without producing a large amount of Vars or amps so the Vars (or thermal capabilities) are held in reserve for extreme low voltage conditions. The transmission bus voltage will likely be the limiting factor during testing and normal operation. It is unlikely that capability curve limit will be reached during either a leading VAR test or during collection of operating data. The limiting factor again is likely to be the transmission bus voltage. Likely unit operational limits which will prevent demonstration of the full range of the generator capability curve include the minimum excitation limit, the generator minimum voltage limit, or the station service minimum voltage limit. We recommend the Remarks statement be replaced with a list of possible limiting factors with checkboxes. If the transmission system voltage or a plant voltage limit is the limiting factor, the results of the test are inconclusive without performance of a supplemental engineering study. 9) The responsibility for requiring and coordinating any staged testing for the purposes of model validation already resides with the owners of the transmission models (i.e., the PC, TP, TOP and/or RC), not the GO or GOP. See TOP-002-2b R13. The TOP should initiate the request for the test and work with the GO/GOP to schedule the testing at a time when system conditions are optimal for testing that specific unit. The GO/GOP should only be responsible for supporting the TOP/RC during test scheduling, conducting the test, recording the necessary plant data, and reporting the test data and results, including any plant limitations encountered during the test. The GO/GOP can also perform any technical reviews and/or additional engineering analysis necessary to determine or confirm the expected MVAR limits to be used in the transmission models. This approach will better serve the reliability purpose of the standard. 10) Measure M1 doesn't match R1, or Attachment 1 or 2 regarding the submission of ambient condition correction information. (appears in M1, but not in the others) 11) An entity should be able to receive credit for real & reactive capability verification that has been done in the past 5-6 years which resulted from following existing regional requirements 12) For cases where operational data is used for verification, submittal of the results within 90 days of the date the data is recorded is inappropriate. Use of operational data involves the review and

evaluation of unit data trends over an entire season as a minimum. Two seasons are optimum based on our experience. R1.2 and R2.2 should be revised to state, “within 90 calendar days of completion of the verification.”
Yes
The footnote number in the clean version is Footnote 4. The footnote reflects our concerns about the validity of data taken from partial load rejection testing when compared to the unit response during normal operating load levels.
No
a) R2 references Attachment 1 for periodicity, yet also includes a "365 day" statement. Please rely on Attachment 1 for the periodicity information and remove the parenthetical element from R2. b) On first glance, it is not clear that pages 14-18 all comprise Attachment 1 - please label each table. c) Please number the rows of the table so that they can be easily referred to. d) The GO is not aware of system frequency excursion events at each of their facilities to see if a Criteria 1 has occurred. e) should row 1 of the table on p 15 include "existing applicable unit"? h) Row 2 should be labeled "Recurring verifications" as "for an existing applicable unit" is superflous to subsequent. i) What is the time frame for the Criterion 1 frequency deviation? j) Row 4 of the table describes what is commonly termed "sister" units - the limitation to allow sisterhood for only those units at the same physical location should be relaxed to include all identical units for the same GO/GOP either within a Balancing Area, or alternatively, within the area of responsibility for a Reliability Coordinator. The GO should be allowed to take credit for units located within the same Balancing Area (or alternatively the Reliability Coordinator area of responsibility) if he can show that the physical location is not a factor in the comparison. k) It is not possible to comply with the R2 25/50/75/100% in 3/5/7/9 year implementation plan and fulfill the trigger verification of Row 5 of Attachment 1 table.
Yes
We agree that base load units should not be required to respond to demonstrate they will respond for underfrequency events and this should be reflected the transmission models.
Yes. 1) Applicability 4.2.1, 4.2.2, and 4.2.3 use the term “bulk power system" and should be “Bulk Electric System (BES)”. We believe the >100kV criteria language should be retained. We believe the exemption for units that, by design, do not respond to frequency should be clearly stated in the Applicability section. 2) It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. We believe this to be true even when it is part of a plant or Facility with an aggregate gross rating >100MVA. NERC is supposed to focus on creating standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. For plants and Facilities with an aggregate rating >100 MVA we recommend deletion of the two sub-bullets in 4.2.1, 4.2.2, and 4.2.3. In conjunction with this change, we recommend that R2, sub-part 2.2 be revised to state, “For plants or Facilities with gross aggregate rating greater than the specified thresholds in 4.2.1, 4.2.2, or 4.2.3, perform verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5. 3) The Eastern

Interconnection frequency excursion criteria of greater than or equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don't provide data that is nearly as meaningful as excursions at 0.06 or 0.07." 4) Measure M2 uses the term applicable "Facilities" while R2 uses the term applicable "units". Either is acceptable to us, but the requirement and measure should use the same terminology. 5) The purpose statement is written in a convoluted form - a more straightforward presentation could be: "To verify the models used in dynamic simulations accurately represent the generating unit real power response to system frequency variations". 6) In Requirement R3, the paragraph above the three bullets would be more appropriate if moved below the three bullets. 7) Consider modifying the implementation plan to allow years for 10%, 5 years for 25%, 7 years for 50%, 9 years for 75%, and 11 years for 100% model verification due to the fact that a learning curve is involved and many entities have large numbers of units.
No
1) Applicability, Section 4: Applicability for PRC-019 and MOD-025 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to be focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their criticality to the system seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where relability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. The individual unit size criterion should match the aggregated plant size criterion.
Yes
Yes. R1, Part 1.1.1 needs clarification. We recommend this be revised to state, "Assuming initial steady state system conditions with the AVR in service, verify the limiters…" Reflect any changes in M1. R1, Part 1.1.2 needs clarification. We recommend this be revised to state, "Confirm the settings determined in Part 1.1.1 have been applied to the in-service equipment." Reflect any changes in M1. Some consideration of changing the five year recurring verification of the coordination required by R2 to a six year period should be performed so that typical 18 month and 3 year outage schedules will coincide with the requirement periodicity. In the applicability sections 5.1 and 5.2, we prefer that the percent complete be "of the entities total applicable MVA" rather than "of its applicable Facilities".
Individual
Thad Ness
American Electric Power
Yes
Yes

Yes
In section 4.2 for Facilities , the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC. Item 5.3 appears to be one exclusive example. What if there are three wind farm sites? AEP agrees with the example given, but 5.3 should contain a high-level statement followed by the example provided. We still oppose using language requiring that a standard be effective by “the first day of the first calendar quarter” x “calendar years following applicable regulatory approval”. It is not clear exactly how this is to be interpreted. For example, if regulatory approval is granted on Feb 1 2013, is the standard effective on Jan 1 2014 or April 1 2014 if “x” is one year? For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year.
No
AEP is not certain that load rejection testing would be an acceptable means of verification, particularly given that a unit is disconnected from the system and the issues alluded to in the footnote. Is the drafting team completely confident that this is an appropriate means of verification and could not produce a mischaracterization of unit behavior during system frequency excursions?
No
The Attachment 1 table is difficult to read, and the information contained could be more clearly conveyed than it currently is. The event triggers and periodicity span across multiple pages, making it a challenge to use effectively. Titling the column “Comments” does not properly describe the information that column contains. Suggest re-naming this column as “Action Required”. Within the section for “Subsequent verification for an existing applicable unit”, it is unnecessary and counter-intuitive to allow the resetting of the period to only occur “within one year of the applicable unit’s ten year anniversary date…”. This should be corrected to state that the verification period could be reset for any frequency excursion occurring “or before the 10 year anniversary date”. Within the “Event Triggering Verification” column (page 16 of the clean version), how is the following combination not non-compliant? “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period” and “Neither an on-line speed governor reference test nor a partial load rejection test was performed”. Attachment 1 has references to "Not required until responsive control mode operation for connected operations is established." AEP does not understand what this statement means.
No
We can find no mention of "base load units" in Attachment 1 or anywhere in the standard, so it is not clear that those units have indeed been exempted. There needs to be more explicit references and/or parameters with respect to the meaning of "base load units" in the body of the standard rather than an implied

reference in the attachment. We don't know what the SDT believes is a "base load unit"; therefore, we cannot support an exemption.
In sections 4.2 Facilities – the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC. In regards to the terms “Load Control” and “Active Power/Frequency Control” used throughout, more than the clarification of footnote 1 seems necessary. Does “load control” refer to turbine and boiler coordinated control? It is our experience that variable energy plants do not regulate active power or frequency. Appropriate models may not exist at the present time for either load control or active power/frequency control. If so, what then? The grammar in the Purpose section could be simplified and made more clear. Should the implementation plan for the effective date of R1 precede the effect date for R3 through R5, by 90 days perhaps? R 2.2: Obtaining an aggregate model would only make sense if the units comprising that aggregate are at least similar if not identical to each other. This needs to be made clear. What happens if units whose response is to be aggregated are not similar? R 2.1.2: It would be beneficial to provide examples for “Type of governor and load control and active power control/frequency control equipment” in perhaps the same manner as MOD-026-1 R2.1.2. This comment form states “The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next.” What is meant by governor response not being consistent from one frequency excursion event to the next? Is this because of deadband or perhaps something else? M2 - it states "... Model was verified and dated evidence of transmission, , such..." we recommend changing the sentence to be "... Model was verified and dated evidence of transmittal, such..." VSL - requirement 5 moderate VSL needs to be changed to say "but less than or equal to 150 calendar days." Also, the "or" statement in that column needs to be changed from "181 calendar days" to "151 calendar days"
Yes
Yes
On the P-Q diagram, it is not clear how the instantaneous field current and instantaneous field current trip shown in the diagram would be relevant to coordination. These two values are not typically provided in such a diagram.
The purpose statement as provided in the standard is not the same as the one stated in this comment form. The VSL for R1 should be graduated. For example, missing one element on a fleet should not be categorized as a severe VSL. Perhaps a system similar to the one (Proposed?) for PRC-005 could be adopted.
Individual
John Bee
Exelon
Yes

Yes
Yes
1) As stated in the previous comments from Exelon to Questions 5, 7, 12, 13 and 14 as documented in the Consideration of Comments on Generator Verification (MOD-025-2) – Project 2007-09 dated 2/22/12 (p81, p106, p150, p156 and p189), Nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. In response to Exelon's comments on Questions 5, 7, and 14 the SDT states that [a nuclear plant] "should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities." In addition, the statement "Auxiliary bus voltage limits should be observed" was added to Note 1 of Attachment 1. As further stated in Summary Consideration for Question 5, the SDT has added Note 4 to Attachment 1 that states that "The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability, or the minimum lagging capability at which it can operate." Exelon requests that this note be further clarified as follows: "The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability or the unit is restricted due to other regulatory, unit stability or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate." In response to Questions 12 and 13 to Exelon's comments, the SDT further states that "Nuclear units are not required to perform Reactive Power verification at minimum Real Power output" as currently stated in Attachment 1 Verification Specification 2.2. Exelon requests this be revised to clearly state that nuclear units should also not be required to perform under-excited (leading) reactive capability verification. Attachment 1 Verification Specification 2.2 should be revised as follows: 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output and are not required to perform under-excited (leading) Reactive Power verification. 2) With respect to all of the Notes provided on the current draft MOD-025 Attachment 1, Exelon requests that the Notes be tied to the verification specification that they are referring to. 3) Historically Exelon has noted that its larger generating units have not been able to attain all of the data necessary for an over-excited full load and minimum load reactive power verification on the same test day due to grid constraints. Please clarify that it is acceptable to perform segments of the reactive power verification on different test days as long as each portion of the test is performed for the required duration. 4) Please explain what is meant by the statement "[T]he recorded Mvar values were adjusted to rated generator voltage, where applicable" in the Summary of Verification section of Attachment 2. 5) The last Section of MOD-025-2 Attachment

2 requires certain Verification Data to be provided by unit or Facility, as appropriate. Exelon suggests that both the "rated" and "as tested" generator hydrogen pressure values be recorded as a comparison. Suggest the following be added to the Summary of Verification in Attachment 2: • Generator hydrogen pressure (if applicable) Rated pressure: _____________ As tested pressure: _____________ 6) In the Consideration of Comments on Generator Verification (MOD-025-2) – Project 2007-09 dated 2/22/12 (p12), the SDT responded to the industry that it anticipated that Regional Standards would be retired once MOD-025-2 is approved. In addition, the SDT added language specifically to the Implementation plan to address the intent of ReliabilityFirst (RFC) to perform a review of both MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC BOT approval of NERC MOD-025-2. RFC has recently announced that they are “suspending Regional Standards efforts.” On the NERC website MOD-024-RFC-01 is RFC Board Approved and MOD-025-RFC-01 is NERC BOT Adopted. Exelon is unsure of the status of both MOD-024-RFC-01 and MOD-025-RFC-01. With respect to the wording added to the Implementation Plan for MOD-025-2; what is the status of the intended review by RFC of both Regional Standards upon NERC BOT approval of the associated NERC MOD-025-2 Standard?
Yes
Yes
Exelon appreciates the additional guidance provided in the Unofficial Comment Form for Project 2007-09, "Generator Verification," that includes specific examples for implementation to aid the industry in understanding the proposed model verification periodicity; however, Exelon is concerned that this information will be "lost" since it is only documented in this format. To ensure this guidance is available to registered entities in the future, Exelon suggests that this guidance, including the four examples, be added to the Implementation Plan for MOD-027-1. The staggered implementation period in the current draft of MOD 027-1 and the additional guidance provided by the SDT, seems to imply, as substantiated by the examples provided above, that before the 1st model verification period at T=0 all recorders are required to be installed and ready to trigger in the case of an ambient event for each generating unit. Please clarify that the staggered implementation allows the applicable generating units to modify/install recording equipment at any time during the three year implementation period at the discretion of the Generator Owner and not that all applicable units should have the recording equipment installed and ready to trigger following regulatory approval of MOD-027-1.
No
As stated in the previous comments from Exelon as documented in the Consideration of Comments on Generator Verification (MOD-027-1) – Project 2007-09 dated 2/23/12 (pp 46-47) the proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure

Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that “Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units...”. The response from the SDT on Exelon's comment was to add an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in control mode, except during normal start up and shut down, that would result in a turbine/governor, and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT further stated that they believe this modification to MOD-027-1 will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode. While Exelon appreciates and agrees with the addition to Attachment 1 (the Periodicity Table) as stated above, Exelon is concerned that this exclusion may not be interpreted uniformly across the Regions or by auditors and therefore suggests that the exclusion be explicit to exempt "base loaded nuclear units that do not respond to grid frequency deviations" and that the exclusion be added to the Applicability section of MOD 027-1. Note that there is no definition in the NERC Glossary of Terms of a "base loaded unit" and in a deregulated environment the term "base loaded unit" is problematic. Therefore Exelon strongly suggests that nuclear units should be explicitly excluded due to the reasons provided above. Exelon suggests addition of the following to the Applicability Section. 4.2.4 Individual base loaded nuclear generating units that do not respond to frequency deviations are exempt from the verification requirements of Standard MOD-027-11 R.2 1Base Load nuclear generating units that do not respond to grid frequency deviations are required to document circumstance for exemption in accordance with Attachment 1 Exelon suggests addition of the following to the Attachment The existing SDT proposed exclusion is as follows: "New or existing applicable unit is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)" Exelon suggests revising as follows: New or existing applicable unit is considered a Base Load nuclear generating unit that is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)
1) Exelon requests that the Implementation Plan for MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions," add a section to provide guidance on the applicability of Base Loaded nuclear generating units that do not respond to frequency excursion events as explained above. In addition to the exemption criteria, more guidance should be provided on the required "document circumstance with a written statement." 2) MOD-027-1 R5 states that the Transmission Planner is to notify the Generator Owner within 90 calendar days whether the model is "useable" (i.e., meets the criteria specified in Parts 5.1 through 5.3). The usability of the model should be that it mimics the generating unit governor regardless of whether the governor/model challenges transmission operating criteria. The requirement as

written implies that a Transmission Planner could challenge the governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09 (as stated in the SAR) which is "[t]o ensure that generator models accurately reflect the generator's capabilities and operating characteristics." 3) Please clarify what is intended by an "applicable facility" with respect to implementation. Is it the intent that the total population generating units that meet the characteristics in Requirements 4.2.1, 4.2.2 and 4.2.3 start as being "applicable units" for the purposes of implementation and then during the staggered implementation, each individual unit is to be evaluated for verification requirements?. For example, if a Generator Owner had ten units (five of which are nuclear units) each greater than 100 MVA and therefore all meet criteria of 4.2.1 then those ten units are in the scope of MOD-027-1 for implementation. This is regardless of any verification requirements that may then exempt them from verification per Attachment 1? 4) MOD-027-1 R1 is inappropriately prescriptive to Generator Owners (GOs). The Transmission Planner (TP) should merely ask for modeling parameters from a GO and not provide instructions on how to obtain acceptable models used in TP software. GOs may not own such software. 5) MOD-027-1 R2 is unclear as to the intended obligations. The sub-bullets in 2.1 should clearly state that following one or two of the sub-bullets are acceptable. Requiring all sub-bullets is too prescriptive and problematic. In the case of 2.1.1, fossil generating units are not likely to have the equipment necessary to demonstrate compliance. 6) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). 7) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted.
Yes
No
Exelon does not believe the SDT adequately addressed the concern previously raised by Exelon regarding Section G as documented in the Consideration of Comments on Generator Verification (PRC-019-1) – Project 2007-09 dated 2/22/12 (p 18). The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (page 7) states "[f]or the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current." This conflicts with Requirement R1.1.1 that states "... assuming normal AVR control loop and system steady state operating conditions." Currently the two statements are in conflict with one another in that one requires a "fixed" field current (i.e., AVR in "manual") and the other requires "normal operation" (i.e., AVR in "automatic"). The response given by the SDT was that "[t]he SDT agrees that the generators must normally operate in AVR mode." This does not address the

conflict identified. The SDT needs to allow for automatic mode for AVR to accommodate those generating units that have redundant automatic channels as is the case for newer digital AVRs. This will allow the Generator Owner to use AVRs automatic mode when plotting SSSL. The response given by the SDT was that "[t]he calculation of the SSSL, based on a fixed-field current value, is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex..." Exelon does not believe this response is acceptable. PRC-019-1 should not force a Generator Owner to use the SSSL curve with the AVR in "manual". There should be an option that allows a Generator Owner to use the SSSL curve with the AVR in "manual" or in "auto." If the Generator Owner wants to use a more complex calculation to plot SSSL curve with the AVR in "auto" (which although more complex would also be more accurate) it should be left to the discretion of the Generator Owner.
1) In the Consideration of Comments on Generator Verification (PRC-019-1) – Project 2007-09 dated 2/22/12 (Question 5 on p 57), Exelon requested that the implementation period by 2 years following regulatory approval. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). An implementation period of 2 years will allow for any modifications to existing equipment be completed during a refueling outage. In response to Exelon's comments on Questions 5, the SDT states that "[t]he SDT does not believe the requirement to have 20 percent of applicable units compliant within the first year is an undue burden. For the example noted, the unit could be verified with the last 20 percent of Exelon’s fleet, which gives over four years to comply with the standard." Exelon does not believe that the SDT fully evaluated the example. Exelon Nuclear is registered with NERC in the RFC Region as a GO/GOP. This registration encompasses 16 generating units which are all nuclear generating units. Exelon Nuclear is also registered with NERC in the SERC Region as a GO/GOP. This registration encompasses only one (1) generating unit which is also a nuclear generating unit. Therefore the explanation given by the SDT to move the nuclear "unit" to the last 20 percent of the implementation period is impractical as it would be for any GO/GOP that has a fleet of all nuclear generating units. 2) PRC-019-1 R1 (or the Applicability section of the Standard) should not apply to facilities currently in service until changes in the protection system are made. Applying this Standard to facilities in service will be a paperwork burden and will have no impact on reliability. It is more reasonable to apply PRC-019-1 R1 to facilities upon changes to the protection system. 3) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). 4) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted.
Individual

Don Jones
Texas Reliability Entity
Yes
R1.2 – We suggest removing the phrase “date the data is recorded for a” and replace with “date of a”. It is not important to note the date on which the data is “recorded” but rather the date a staged test occurred. “Recorded” could have different meanings - is it “recorded” when a Verification Data form or report is finalized internally or when PI Historian captures the SCADA data? Remove “or a form containing the same information as identified in Attachment 2” and change the verbiage on Form 2 (“changes may be made to this form”). If there is a form, require its use to promote consistency. Additional forms can be provided by the TP if needed to cover additional configurations.
Yes
Attachment 1, item 3.2: Is there a requirement for a voltage schedule for a synchronous condenser? Also, if there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. Attachment 2 does not necessarily include Synchronous Condensers.
Yes
1)Facilities--Avoid use of “bulk power system.” There is inconsistency between the Standards in this Project with regard to applicable Facilities. Suggest using BES definitions or Transmission Planner requirements (if TP requirements are inclusive of BES as a minimum). 2)Effective date 5.3: ”Wind site” is not defined. 3)Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning models for specific periods. 4)It is unclear whether this Standard requires Gross or Net (or both) capabilities to be verified. The Attachments seem to allow for either, to some degree, but is not definitive. It should be clearly stated which is expected. The following comments refer to the Attachment 1: 5)In Attachment 1 the term “commercial operation date” is used. The phrase should be more along the lines of “initial synchronization to grid,” as a commercial operation date may be an extended time from initial synchronization. In general, there would be manufacturer’s data that may be used in models but it is critical to understand the capabilities early on. 6)How does one determine what changes are “expected” to make a 10 percent change in last reported capability? We suggest deleting “is expected to.” 7)Attachment 1 item 2.1: We recommend changing the real/reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. Also, we recommend changing the first sentence as follows: “Verify gross and net Real Power capability, gross and net Reactive Power capability over-excited (lagging) and gross and net Reactive Power capability under-excited (leading)……”. 8)Attachment 1 item 2.2 appears to allow wind and photovoltaic “applicable facilities” to not have to verify Reactive Power capability at a minimum Real Power output. Is that the expectation of the SDT? At least in 2.1 there were statements regarding what was expected of wind and photovoltaic Facilities for Real and Reactive Power at expected maximum Real Power “at time of the verifications.”

9)Attachment 1 item 2.3: What is the basis for “one continuous hour?” What is the expected value(s) to be provided for the continuous hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and wind turbines may not allow for a full hour. Additionally, system conditions must be taken into effect for tests (disturbances that do not necessarily put the system into an emergency situation but may impact capability). Current ERCOT regional criteria for the Reactive Power leading and lagging tests is 15-minutes. 10)Attachment 1 item 2.4: Is this meant to be an instantaneous value to be collected? Or do the units have to maintain the verified value for an hour? Is the intent of 2.4 captured in 3.1 (as 3.1 appears to be a value recorded at the end of the verification period)? 11)Attachment 1 Section 3 does not include all the measurements shown in Attachment 2. While Form 2 may be changed (hopefully under the direction/guidance of the TP), section 3 should at least capture what measurements are portrayed in the Attachment 2 form as it exists. 12)Attachment 1 item 3.2: This is unclear regarding seasonal expectations and how to capture those expectations in a verification activity. As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. 13)Attachment 1 items 3.3 and 3.6: “Interconnection” should not be capitalized. 14)Attachment 1 item 3.4: Should include “Others as applicable” to match Verification Data form. 15)Attachment 1 item 3.8 is not captured on Verification Data form. 16)Change MVAR to Mvar in the “Notes” section of Attachment 1. Attachment 2 17)The first part of Attachment 2 assumes a single point of interconnection (Point F). Should there just be a requirement to supply a detailed one-line with measurement points noted and remove the sample one-lines? 18)In the Verification Data form, the use of the phrase ”connected at the same bus” may have different interpretations than expected. Suggest removing the phrase or at a minimum changing the phrase to “measured at sites connected to the low side voltage level(s) of the GSU”. It should be noted that Auxiliary and tertiary loads (in terms of Real and Reactive Power) are not necessarily “connected at the same bus.” 19)Why is “N/A” in a few locations on the Verification Data form? 20)Please change the Verification Data form to use the same terms in the definitions of Net Reactive and Net Real Power (form calls for Gross Reactive Power Generating Capability” but definitions of Net do not use same term). VSLs 21)VSLs for R1- Suggest matching the language of the requirement with regard to “date the data is recorded for a staged test” or to the changes suggested for R1 (“date of a” staged test). 22)VSLs for R1- Suggest matching the language of the requirement with regard to “the date of the historical operating data that was selected.” The Requirement states “the date the data is selected for verification using historical operational data” which may be different than the date of the historical operating data (that was selected). 23)VSLs for R1- The second “OR” statement is not auditable if the Verification Data form is allowed to be changed. If the form had a minimum data requirement that had to be provided, a VSL could be created. As written, the statement “The Generator Owner verified the Real Power capability and submitted the data but was missing 1 to 33 percent of

the data” and variations thereof cannot be audited. 24)VSLs for R1- Suggest adding “Real Power” in the third and fourth “Or” statements as R1 only refers to Real Power—“The Generator Owner performed the Real Power verification…” 25)Severe VSL for R1- The last “OR” statement needs corrected as it is the same language for the Lower VSL. Suggest changing to the following: “The Generator Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months. “ 26)R2 VSLs have the same comments as R1 VSL with the exception of adding “Reactive Power” instead of “Real Power” in the suggested locations. 27)R3 VSLs have the same comments as R1 VSL with the exception of adding “Reactive Power” instead of “Real Power” in the suggested locations. Additionally, there are multiple references to “Generator Owner” that should be replaced with “Transmission Owner.”
No
Only base-loaded units that are nuclear units should be exempted.
1)Applicability: a.Section 4.2: Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements, whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection. The applicable Facility requirements should be the same for each Standard in this Project! b.Section 4.2: We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. c.The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an “applicable unit”, then wait until a frequency excursion occurs to measure performance, then has 365 days to send the model data to the Transmission Planner. 2)Effective Dates: a.Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correct model errors that may lead to (or have led to) improper planning of the system based on the current model results. b.For establishment of initial verification period, the MOD-027 Attachment 1 “OR” phrase is inconsistent with the timeframes to be compliant per the effective dates (e.g. If a unit records a response on the “Standard Implementation Effective Date” and then has 365 days to send the data, how can it meet the 25% compliance requirements on the first day of the first calendar quarter three years following regulatory approval?) What is the “Standard Implementation Effective Date”. c.The SDT should consider moving the Consideration for Early Compliance criteria from Attachment 1 into the Effective Dates section. 3)R3: The inclusion of “or a plan” extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Do the plants need to disconnect until “usable” data

is provided? 4)R4: The inclusion of “or plans” extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Ddo the plants need to disconnect until “usable” data is provided? 5)VSL R2: The Severe VSL language is different from the Lower, Moderate, and High VSL language regarding the models. Language should be consistent. 6)The following comments relate to Attachment 1: a.R3: The timeframes are too long. If a GO has a unit that the TP had deemed not “usable” it has 90 days to produce a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response—then has another 365 days to send the data to the TP. What does the TP do in the interim? b.R4: The timeframes are too long. If a GO has a unit that undergoes changes to the “turbine/governor and load control and active power/frequency control system” it has 180 days to produce the model data OR a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response—then has another 365 days to send the data to the TP. More time would be needed if the TP took 90 days to verify the model data and possibly 90 more days by the GO to defend the model data, changes or verification plan (per R5 and R3). What does the TP do in the interim? c.Comment column: How do “Comments” get used in an audit? If there is a requirement to transmit information within a certain timeframe, that should be included in the “Verification Periodicity” column and not the “Comments” column. d.Criteria 4: If there are going to be references, give the references a number rather than referring to “4th row in the following table”.
Yes
Yes
1)Purpose: Suggest replacing the phrase “equipment capabilities” with the NERC-defined term “Facility Ratings”. 2)R1.1.1: Suggest breaking this up to make the requirement clear. R1.1 Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility: 1.1.1 Limiters and the Protection System for the applicable Facility are set to allow full capability within the Facility Ratings of the applicable Facility and steady-state Stability Limits; 1.1.2 Limiters are set to operate before the Protection System of the applicable Facility; 1.1.3 The Protection System of the applicable Facility is set to operate, isolate or de-energize equipment, in order to protect equipment from damage when operating conditions exceed Facility Ratings or Stability Limits; 1.1.4 Settings determined in Parts 1.1.1 through 1.1.3 are applied to in-service equipment. 3)R2: Remove the phrase “the existence of” in the first sentence. Recommend re-wording as follows “Each Generator Owner and Transmission Owner shall verify the coordination identified in Requirement R1…..”. 4)R2: Suggest considering removal of the phrase “are expected to” as this is somewhat arbitrary and could lead to differences in application of the Standard. The VSL for R2 has the following phrase “identification or implementation of a change that affected the coordination” that indicates the GO or TO verified ONLY coordination on changes that affected the coordination (rather than what the Requirement states with the phrase “are expected to”). If the phrase “are expected

to” is meant to bolster coordination efforts than the VSL language should address the same concept. 5)R2: Suggest re-wording three bullets as follows (leave 4th bullet unchanged): • Voltage regulating equipment settings or component changes • Generating or synchronous condenser Facility Rating changes • Generating or synchronous condenser step-up transformer Facility Rating changes 6)M1: Suggest replacing the phrase “applicable Facility capabilities” with “applicable Facility Ratings”. Also, suggest replacing the word “capabilities” with “Facility Ratings” in the 3rd bullet of M1. 7)VSL R1: Suggest rewording as follows to match the R1 requirement, “The Generator Owner or Transmission Owner failed to coordinate the voltage regulating controls and Protection System settings with the applicable Facility Ratings as specified in Requirement R1.” 8)VSL Severe R2: Remove the phrase “the existence of” in both sentences. Recommend re-wording as follows “The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1…..”
Individual
Ed Davis
Entergy Services, Inc
Yes
Yes
Yes
Yes: • VAR-002-1.1b Requirement R1 states “The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.” However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. Entergy recommends that MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the Entergy recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard. • On Attachment 2 Comment Section for Point A, add note that “individual unit values are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) • On Attachment 1, item 2.6, add sentence stating that “GSU

transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.” If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. • On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. • Entergy recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of “sister unit” concept. This will facilitate more consistent unit verifications. • Entergy agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. Recommend that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar changes which impact the reactive testing results. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities.
Yes
No
Regarding the terminology in Attachment 1, “Turbine/governor and load control and active power/frequency control”, should all the “and”s in the Event Triggering Verification column be “or”s? Entergy recommends that this be reviewed for consistency.
No
Entergy sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification.
Entergy found this excerpt (section 4.2.1 bullet 2) below to be confusing, particularly the second sub-bullet below: • For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating); and o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings Could the

SDT provide some examples of how this would work? Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability.
Yes
Yes
There needs to be a requirement that the GO protection coordinate with the steady state stability limit. Entergy recommends inserting "or reach steady state stability limits" after "equipment" in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions. Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Entergy recommend that you stay with a 30 day increment. Also in R2 you need a space between "5years".
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
Yes
Yes
Yes
FirstEnergy has the following comments related to Attachments 1 and 2: 1. Att. 1 Sec. 2 – We suggest replacing the phrase "that demonstrated at least 50 percent of the capability of the associated D-curve" with "that demonstrated the maximum capability of the associated D-curve". In addition, we suggest language as follows: "The reason(s) for any verified Reactive Power capabilities that, due to plant equipment, are more constraining than the appropriate generator Reactive Power capability curve (D-curve) shall be documented. (For example, exciter or generator field current limitations, generator terminal voltage, auxiliary or safety-related bus voltage limitations, volts per Hz alarms, excessive generator vibration, generator temperature limits, hydrogen coolers restrictions, shorted rotor turns, safety, other protection, etc.) 2. Att. 1 Sec. 3.4 – Although we understand the drafting team does not want to be prescriptive and dictate an ambient temperature methodology, we believe the requirement is too broad and up for much interpretation across entities and regional auditors. There should be a more standardized method of determining the ambient adjustment for consistency, for example something similar to RFC standard MOD-024-RFC-01 Requirement R4.3. 3. We suggest adding the following or similar wording in the standard when a verification cannot be

completed due to operational issues and include the allowance of engineering analysis to complete the verification: “1.2.3 If a verification test has been started and cannot be completed due to a transmission system limit or condition, this transmission system limit or condition shall be documented, and engineering analysis taking into account known limitations shall be used to determine the verified capabilities.”
Yes
FE offers the following comments and suggestions: 1. We are concerned that a regional or interconnection-wide excursion from the scheduled frequency may impact potentially an entity’s entire generation fleet and the time frame of 365 days per R2 and Att. 1 may not be feasible. We ask the team to take this into consideration and add more time for these scenarios. 2. Disturbance Monitoring Equipment (DME) necessary to obtain recorded data from excursions may be owned by the Transmission Owner and not the Generator Owner. The team may also want to consider how this MOD-027-1 standard is coordinated with the NERC PRC-002 DME standard that is still in development.
Yes
Yes
R1 – The term “In-service” should not be capitalized
Individual
Matthew Pacobit
AECI
No
I belive that a one continuous hour test for reactive testing will not increase reliablity. Most units are not used for long periods of time for reactive power. I am also worried about damage do to High winding tempetures during this test.
Yes
Yes
Yes
Yes
Yes

No
I Believe that the Ratting should be 100 MVA for all Generating units
Yes
Group
PacifiCorp
Sandra Shaffer
PacifiCorp
Yes
Yes
Yes
Yes. See below: PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.1 of the "Applicability" section (as well as to sections 4.2.2 and 4.2.3). The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence would reads as follows: "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to Section 4.2.2 and 4.2.3.
Yes
Yes
Yes
Yes. See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of 4.2 - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for the first bullet under section 4.2.2): "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made throughout section 4.2 where applicable. 2. PacifiCorp believes that the sub-bullets of the second bullet under Section 4.2.2 of the "Applicability" section (and elsewhere, as applicable) introduce confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following

language to replace the two existing sub-bullets under the second bullet of section 4.2.2: • "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and • Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5."
Yes
Yes
Yes. See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of Section 4.2. - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for section 4.2.1): "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to section 4.2.2 and 4.2.3.
Group
SERC Planning Standards Subcommittee
Charles W. Long
Entergy Services, Inc.
Yes
Yes
Yes
* Change references to “bulk power system” in the Applicability section to “Bulk Electric System.” * VSL’s for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33. * VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from “more than 12 calendar months but less than or equal to 13 calendar months” to “greater than 15 calendar months.” * Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50

percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word “reactive” be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." * Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. * Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires..."
Please check footnote numbering. Footnote 5 in the redline version is labeled footnote 4 in the clean version.
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
Group
Florida Municipal Power Agency
Frank Gaffney
Florida Municipal Power Agency
No
FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards) To parallel the Section 215 definition of BPS at (a)(1) "The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..." We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is

that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn't already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard.
Yes
See comments to question 2
No
The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? We recommend numbering the rows in the table so that row references are clear.
No
As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly.
See response to Question 2 regarding the improper use of the term bulk power system
No
See response to Question 2
Individual
Randall McCamish
City of Vero

No
No
FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards) To parallel the Section 215 definition of BPS at (a)(1) "The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..." We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn’t already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard.
Yes
See comments to question 2
No
The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the

next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? We recommend numbering the rows in the table so that row references are clear.
No
As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly.
See response to Question 2 regarding the improper use of the term bulk power syst
No
See response to Question 2
Group
PPL
Annette M. Bannon
PPL Generation, LLC
No
Suggest changing “Intended” to “preferred” in the Att. 1 statement, “It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”
Yes
Yes
Comments: a. A reference to power factor is needed in para. 2 of the Att.1 verification specification statement, “at least 50 percent of the capability shown on the associated D-curve.” Is this criterion intended to apply at 1.0 PF? b. Para. 2.1 of the verification specification in Att.1 is unclear in citing, “normal (not emergency) expected maximum Real Power.” Normal operating level is typically not the maximum of which a unit is capable. Suggest this test-to generation be changed to, “normal full-load Real Power,” defined as the output at which the unit usually runs for the ambient conditions existing at the time of the verification. c. Add, “for the conditions existing at the time of the verification,” at the end of the first sentence of para. 2.2 in the verification specification in Att.1. d. Change “collect” to “correct for” in verification specification para. 2.6 in Att.1. e. The statement, “The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions,” in para. 3.4 of the verification specification of Att.1 is not clear. Possibly an “if” was intended before “the Generator Owner.” A reference condition is also needed, or instructions for identifying the correct-to criteria, if the as-tested normal real power is to be adjusted for ambient conditions. Such correction often does not apply for the purposes of this standard, however. A fossil

unit with an emergency max capability of 750 MW on a 90 F day can achieve higher output at 60 F, for example, but the normal output may be 725 MW regardless of ambient conditions (see comments above). f. Add, “Transformer Real and Reactive Power losses will also be estimates or calculations,” to para. 4.1 in the verification specification of Att.1, as well as the statement, “Only output data are required when using a computer program to calculate losses or loads.” g. Note 2 the verification specification of Att.1 states, “While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification.” It is unclear who supposed to undertake such analyses and how they could be performed. Suggest this note be clarified or dropped. h. The purpose of having a MOD-025 standard is undercut by the statement in Note 4 of the verification specification in Att.1 that “The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.” It is unclear why these tests should be performed if the results aren’t used? Could MOD-025-2 be withdrawn in light of FERC’s March 15, 2012 FFT Order to propose specific standards or requirements that should either be revised or removed due to having little effect on reliability or because of compliance burdens. i. Add “Reactive Power” between “unit’s” and “capabilities” in Note 4 of the verification specification in Att.1. j. It appears that the aux and net values requested in Att.2 are intended to be low-side readings, in which case they should be so-identified. k. Delete from Att.2 the statement, “The recorded Mvar values were adjusted to rated generator voltage, where applicable.” Such adjustments may have unsuitably high uncertainty.
No
Comments: a. The referenced footnote is number 4, not 5. R2.1.1 and the verification table later in the standard allow the alternative of an on-line speed governor reference change test. In any event the standard requires that, if a naturally-occurring disturbance meeting Criterion 1 does not occur within the specified ambient-monitoring period, we must create one. We are opposed to making it mandatory that GOs conduct such testing. An on-line speed governor reference change test is not always possible. Where it is possible there is risk of creating a larger-than-desired disturbance, possibly threatening grid stability or tripping the generation unit. At the very least there would be a shock to the equipment and some loss of life. The same applies for a partial load-rejection test. It is meanwhile unclear how invasive such episodes would be. Power Technologies, in their paper “Testing Methods, An Overview,” states that five episodes may be required. These are expected to be hard trips, in which case the data gathered may be less useful than the GVSDT is expecting. Rejection to house load, followed by rapid re-synchronization, cannot be expected because need to avoid overspeed due to full-load rejections requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. This is an unreasonable burden to place on GOs, especially when there has not been any commensurate reliability benefit identified. The rationale in MOD-027-1, “to ensure modeling data is accurate,” is far from compelling, nor is it explained why the accuracy of our present, OEM-generated data should not be equal-to or better than

that identified via testing. b. The response adjustment described in footnote 4 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide high-speed recordings of responses to grid disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is there any purpose to making GOs develop models or en masse hire consultants to do so.
No
We must wait for naturally-occurring disturbances, if not creating upsets of our own, making it impossible to guarantee up-front that the 25%-3 yrs, 50% - 5 yrs etc requirements will be met. Such requirements also conflict with the instruction in the periodicity table to, “Record unit Real Power response to the first frequency excursion event that meets Criteria 1 on or after the Standard Implementation Effective Date.” The row in the same table for, “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period, and neither an on-line speed governor reference test nor a partial load rejection test was performed,” meanwhile appears to pertain to circumstances that are not permitted by this standard.
No
We do not see in MOD-027-1 any language that defines baseloaded units as being verified and consequently exempts them from testing. It is true that a gas turbine running at the OEM-established baseload firing temperature is maxed-out and will therefore not exhibit any response to a frequency dip, but it is unclear what units are “always base-loaded.” We also do not see any suitable definition of the term, “base loaded unit.” The NERC Glossary defines “Base Load” as, “The minimum amount of electric power delivered or required over a given period at a constant rate;” but so-called baseloaded units may not run at a constant rate, instead often cycle between full output and minimum load on a daily basis.
Comments; a. The comparison of actual and expected response in R2.1.1 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide also high-speed recordings of responses to grid-disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is clear that there any purpose to making GOs do so. b. R1 should state that generation equipment OEM models are acceptable. This is the source of information we presently have for representing the dynamic response of our equipment. It is probably also the best source of data possible.
Yes
No
The draft standard is technically sound, but additional clarity may be needed to enforce it in a uniform and unambiguous fashion. The GVSDT should list in section G all relays and associated excitation system and voltage regulator functions that, if present and active, are covered by this standard.
Comments: a. Change “capabilities” in the third bull-dot under M1 to “ratings.” b. Having limits set before trips, and trips before damage, is a necessary part of the generation plant design process, so the requirements of the proposed standard in

this respect are just business as usual. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in GO possession. We suggest that PRC-019 be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability.
Group
Transmission Access Policy Study Group
William Gallagher
Transmission Access Policy Study Group (please see www.tapsgroup.org for a list of TAPS' more than 40 members)
No
The SDT states that it "felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry Criteria and the BES definition." TAPS agrees that the standard should be consistent with the BES definition. Given that the MVA limits in the BES definition (and the Registry Criteria) may change, TAPS believes that the standard should not contain numerical limits. Moreover, the standard should be based on the BES definition, which delineates the elements subject to Reliability Standards, rather than on the Statement of Compliance Registry Criteria, which instead defines the entities that must comply with Reliability Standards. We believe that the SDT's concern about synchronous condensers can also be addressed more effectively without incorporating text from the current Registry Criteria. TAPS therefore suggests that the Applicable Facilities section be revised as follows: "For the purpose of this standard, the term, 'applicable Facility' shall mean 'BES generator,' except that a generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator's restoration plan is not an applicable Facility for the purpose of this standard. For the purpose of this standard, a synchronous condenser is treated as a generator."
As stated with respect to MOD-025 in TAPS response to Question 2 above, the Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of MOD-027 be revised as follows (note that we have suggested no changes to section 4.2.3 because TAPS has not investigated the relevant conditions in ERCOT): "For the purpose of this standard, the term 'applicable Facility' is considered, 'applicable units.' Units or plants with an average capacity factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following: 4.2.1 BES generating units/plants connected to the Eastern or Quebec Interconnections with

the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 100 MVA (gross nameplate rating). 4.2.2 BES generating units/plants connected to the Western Interconnection with the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 75 MVA (gross nameplate rating). ... A generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator’s restoration plan is not an applicable Facility for the purpose of this standard.”
No
As stated with respect to MOD-025 in TAPS response to Question 2 above, the Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of PRC-019 be revised as follows: “For the purpose of this standard, the term, ‘applicable Facility’ shall mean ‘BES generator.’ For the purpose of this standard, a synchronous condenser is treated as a generator.”
Individual
Greg Rowland
Duke Energy
Yes
However, see our response to Question #4.
Yes
Yes
• R1 requires the Generator Owner to verify Real Power capability per Attachment 1, and submit the data per Attachment 2. While Section 3.4 of Attachment 1 requires collection of ambient condition measurements needed to perform corrections to Real Power for different ambient conditions, MOD-025-2 doesn’t require that the Generator Owner make corrections for specific conditions (such as summer peak day, etc.), and also doesn’t provide for the Transmission Planner to request verification for any conditions other than whatever conditions existed during the verification required by this standard. Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that’s not included in R1, Attachment 1 or Attachment 2. MOD-025-2 should either specify the conditions for which the Generator Owner must make corrections to real power, or should require the GO to make corrections to any conditions when specified/requested by the TP/TOP. A requirement should be added for the Generator Owner to provide the Transmission Planner with verification of Real Power capability for different ambient conditions within 90 days of a request by the Transmission Planner. • R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and

Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which engineering analysis is required for model verification. SERC developed a generator model validation guide in ~ 2004, which laid out a process where an engineering review and operating data should be performed first and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the region's planning and generator operators. • Attachment 2, Summary of Verification – Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) • Applicability Section – change "bulk power system" to "BES".
Yes
No
The Eastern Interconnection frequency excursion criteria of greater than or equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don't provide data that is nearly as meaningful as excursions at 0.06 or 0.07.
No
Where in this standard is this exemption for base load units? Regardless, base load units do exhibit some response, and the data collection is not difficult to accomplish.
• Applicability Section 4.2 Facilities - Need to specify "net" or "gross" capacity factor for the calculation. • R2, 2.2 – Insert the phrase "or individual unit" after the word "aggregate".
No
• Comments: We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. • Sections 4.2.1, 4.2.2, 4.2.3 – replace "bulk power system" with "Bulk Electric System (BES)".
Yes
Individual
Michael Goggin

American Wind Energy Association
Yes
Yes
Yes
Overall, the draft standard is well-drafted and well help to improve reliability, and I would like to see it pass this round of balloting. If there is another round of revisions to this draft standard, it may make sense to look at this recently added section to make sure that it is a workable requirement for all wind projects: “If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold.” For some wind plants, it may be difficult to schedule a test or retest at a time when 90% of the wind turbines are producing. Some wind plants may have significant periods of time when they have fewer than 90% of their wind turbines producing for reasons beyond their control (wind resource availability), and it is typically not possible to predict when those time periods will occur more than a day or two in advance. Repeated attempts at retests until one coincides with a period of sufficient wind resources may not be the most efficient process for testing a plant. Obtaining additional input from wind plant owners would help to clarify this issue, and if that input indicates a concern, the drafting team may want to change the 90% threshold or provide additional flexibility in the testing process to ensure that this standard will be workable for all wind projects.
Yes
Yes
Yes
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
no comment

no comment
1)Under 4.2 Facilities, IMPA recommends replacing bulk power system with Bulk Electric System which is used in NERC Standards. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)M1 states that the Generator Owner will have evidence that it submitted a correction for ambient conditions. In requirement 1, it does not state that the Generator Owner shall submit a correction for ambient conditions. Either requirement 1 or Measure 1 needs to be corrected to the intent of the SDT. 3)While realizing that the field or armature may be the limiting component in certain segments of the a generator's capability curve, IMPA does not see any value in making a generating unit verify its under-excited Reactive Power capability and over-excited Reactive Power capability at minimum Real Power. Operation at these points at minimum Real Power will seldom if ever happen. IMPA recommends deleting the requirements for reactive capability at minimum Real Power. 4)When at maximum Real Power, it is not clear what over-excited Reactive Power level a generating unit is to maintain for an hour when at maximum Real Power to constitute an acceptable test. IMPA believes in many instances units will reach a limit, such as volts per hertz, and will not be able to reach the over-excited reactive power curve. A Reactive Power test should be acceptable as long as it stays at a documented, reached limit for an hour and should not be required to retest within 6 months. IMPA recommends that the SDT makes its intent clear on what constitutes an acceptable test when at maximum Real Power and over-excited Reactive Power capability.
No comment
No comment
No comment
1)In section 4.2. under Facilities, IMPA recommends changing bulk power system to Bulk Electric System. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)IMPA supports the use of average capacity factor in the Facilities section of the standard.
No comment
No comment
1)In section 4.2. Facilities, IMPA recommends using Bulk Electric System instead of bulk power system. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2) IMPA believes that this standard does not increase the reliability of the Bulk Electric System and tends to be an expensive and administrative burden to smaller entities. In addition, IMPA does not see how this standard is a performance based standard which NERC determined to be the course of the future for reliability standards. IMPA believes that the industry does not need this standard. 3) IMPA does not understand why this needs to be performed once every five years if none of the equipment has been changed.
Group
ACES Power Standards Collaborators
Jason Marshall
ACES Power
No

While we agree with the intent, we believe that Parts 1.2 and 2.2 collectively limit the tests to be no further than 90 days apart. Both parts state that Attachment 2 or another form that contains the same information must be completed within 90 calendar days of the staged test or date the operational data is selected. Since both have real and reactive power entries, can the form be considered completed without both sets of data? If the SDT intends for these real and reactive power tests to be completed greater 90 days apart, some additional clarification needs to be made to Part 1.2 and 2.2. Perhaps a note at the beginning of Attachment 2 explaining that MVAr will not be completed for a real power test and MVA will not be completed for a reactive power test will be sufficient.
No
While we agree to limit the inclusion of synchronous condensers to 20 MVA, we disagree with two other aspects of the applicability. We disagree with inclusion of Blackstart Resources and applicability to the bulk power system. Blackstart Resources should not be included within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, the purpose of their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during the restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies that standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities

that are or are not material to the reliability of the bulk power system. We also find section 5.3 regarding wind farm verification confusing. What is its purpose? What if a wind farm has more than two sites? Why is it specific to a single technology?
Yes
We disagree with testing a unit with capability to operate in synchronous condenser mode in that mode. Most likely the unit would only operate in this mode in an emergency situation. Thus, it does not make sense to operate a unit in an emergency mode for a test. We do not agree with adding a last verification data column in Attachment. This only causes confusion. Will it be clear to auditors that the last verification data column is to remain blank for the initial verification or will we end up with a similar situation to the Protection System Maintenance and Testing standard where auditors required evidence from before the enforcement date of standards? Ultimately, the NERC CEO had to overrule this situation. Furthermore, it creates additional work to transfer data from a previous verification test to the current test when the past sheet could simply be retained. Finally, it causes confusion with the data retention section because the data behind Attachment 2 must be retained. Is this intended to be only the latest verification or does it include the last verification? Item 2 of the verification specifications for applicable Facilities in Attachment 1 conflicts with Parts 1.2, 2.2, and 3.2 of the Requirements R1, R2 and R3. The attachment states that historical data going back two years can be used. However, the requirement parts state that the data must be submitted with 90 days to the Transmission Planner. That would appear to limit the historical data to 90 days. The attachment never makes it clear if you can switch between operational data and staged verification from one test to another. The confusion is caused by the separate listing of periodicities in items 1 and 2 under the “Periodicity for conducting a new verification” section. A close reading of the two items shows they are identical but listed separately to make the statement about listing the “earliest date of those dates” for the operational data. We suggest combining item 1 and 2 together will help eliminate this confusion. We disagree with the need to conduct another staged test rather than using operational data as specified in Attachment I subsection 2 in the “Verification specifications for applicable Facilities:” section. If operational data can be used to satisfactorily verify the unit’s real and reactive power output, it should always be allowed to avoid the need for a staged test.
Yes
We are assuming the question really intended to reference footnote 4.
No
We appreciate the examples and believe they go a long way towards highlighting the drafting team’s intent. However, we do not believe the examples are consistent with the requirements. We agree the examples are how the requirements should be implemented but we simply believe they have not documented the requirements in a way that is consistent with the examples. The first example does not seem to be completely consistent with the standard and also contradicts itself. For instance, the language in Row 2 of the table in Attachment 1 states that the subsequent verification must occur within one year of the applicable unit’s ten year anniversary

of the previous collection date. This could be interpreted meaning it must occur between year 9 and 11. However, the example states (in the sixth sentence) that it must occur after the “10-year period” but then later on (in the eighth sentence) states that monitoring must begin for suitable events must begin “one year before the unit’s 10-year anniversary date of the collection” of data per the Periodicity Table. Nothing in the table says anything about beginning monitoring. Furthermore, it does not make sense to limit a Generator Owner to monitoring for events within one year data collection anniversary date. A Generator Owner should be free to collect data at more frequent periodicities. If they choose to update the model based on these periodicities, the “clock” for subsequent verifications should be reset. The standard should only require that the data is collected and model verified by the given date. The example also seems to support the idea that “within one year” in the table is intended to be 9 to 11 years given that the subsequent data collection occurs between Years 10 and 11. We support the concept of beginning monitoring in year 9 for the second example but believe the standard language as written does not support this concept. As a result, example 2 would appear to represent a compliance violation. Row 2 in the table in attachment 1 states “Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit’s ten year anniversary” or to perform an “on-line speed governor reference change test or partial load rejection test”. It does not say to begin monitoring. It is unequivocal that the subsequent test must occur within 11 years given the language. We suggest updating the table language to clarify that an entity must be begin monitoring for frequency excursion events in Year 9 but one may not be recorded until well after 10-year anniversary (including more than a year). Example 4 helps highlight the issues of the language in the standard. Row 6 requires the Generator Owner to record the “first frequency excursion event that meets Criteria 1”. Row 2 of the table requires that a frequency excursion event that meets Criteria 1 must be recorded “within one year of the of the applicable unit’s ten year anniversary date”. From row 6 and the examples, it would appear the drafting team intended this to begin monitoring within one year to record the first frequency excursion event that meets Criteria 1. We agree with this concept and suggest modifying row 2 language to: “Record unit Real Power response for first frequency excursion event that meets Criteria 1 no later than the ninth anniversary date of the collection of the recorded unit Real Power response used for current validation.” This language will clarify that an event earlier than the ninth anniversary may be used and also clarify that first frequency event after the ninth anniversary must be used (if an earlier event is not voluntarily used) without limiting that the event must occur within Years 9 and 11. We also believe the examples should be added to the standard as an attachment. Otherwise, they will not be part of the standard and the drafting team’s intent could be lost to an auditor. We are concerned that much of the “Or” language in the Periodicity Table regarding waiting to observe a frequency excursion or perform an on-line speed governor reference change test or partial load rejection test could be interpreted as requiring one of these two tests if a frequency excursion is not observed within the appropriate time frame. We believe the language needs to be clarified that a Generator Owner is not required to stage a test if no frequency excursion event is observed.

No
Conceptually, we agree with the concept of an exemption. However, it is not clear to us where this exemption is located within the standard and how it would even apply. Given the penetration of large amounts of wind and record low natural gas prices, many units that might traditionally be based load might actually operate below the maximum capabilities frequently. Our first question then, is what does it mean to be based loaded and what units qualify? Second, what does an exemption mean? Does it mean that a frequency excursion does not have to be observed or an on-line speed governor reference change test or partial load rejection test does not have to be performed? If so, does a model still have to be provided? Any exemption must be explicitly clear to avoid ambiguity and to ensure that auditors will interpret the exemption in the same manner as registered entities.
We believe that this standard is overly administrative by memorializing the interactions between the Generator Owner and Transmission Planner that occur to model the generator’s turbine/governor and load control and active power/frequency control systems. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. The FFT process represents one such effort to eliminate these backlogs. Interestingly, within the approval order for FFT, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard. Requirement R3 allows a Generator Operator to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner’s model issue. Thus, this requirement does nothing for reliability because modeling problems can be left unsolved. It should be struck. We are not convinced Requirement R4 is needed. The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of applicable control system changes. In the first bullet under Requirement R3, we suggest referencing Requirement R5 regarding “useable” to make it clear that useable is in essence defined in Requirement R5. Otherwise, the reader may not realize that Requirement R5 sets the parameters on what “useable” is. We do not believe simply putting useable in quotes is enough. The numbering of the section 4.2 is not consistent with the parallel MOD-026-1 standard. MOD-026-1 uses numbers for each sub-section while this standard uses primarily bullets. It would be easier to reference and comment if numbers are used rather than bullets and would be consistent. The second bullets of Sections 4.2.1, 4.2.2, and 4.2.3 are confusing and potentially contradictory. First, these sections state that they apply to each

generating plant/Facility greater than 100, 75 and 75 MVA respectively. Then, the second sub-bullet (under the second bullet) applies to generating plant/Facility. How can there be a plant within a plant? With the first sub-bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 75 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for individual generating units than first main bullets which apply to individual generating units. For example, the first main bullet in section 4.2.2 applies a 75 MVA threshold to an individual generating unit and then second sub-bullet applies a 20 MVA threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. The NERC Glossary of Terms uses a generator as an example of a Facility. In the second sub-bullet, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. The first main bullet under section 4.2.3 in the Facility section uses 50 MVA while the second bullet uses 75 MVA. This is not consistent with section 4.2.1 and 4.2.2 which use the same value for both bullets. Is this intentional? The purpose statement appears to have an extra “that”. It begins with “that accurately represent” and is in the second to last line. Part 2.1 includes an ambiguous statement about using a model that is acceptable to the Transmission Planner. We assume the intent was for the Generator Owner to use a model identified by the Transmission Planner in Requirement R1. If so, we suggest changing “acceptable to the Transmission Planner” to “identified in Requirement R1”. Otherwise, the Generator Owner may be compelled contact the Transmission Planner for an attestation that the model is acceptable. This further ensures that everyone (registered entity and auditors) interprets that language to mean those models identified in Requirement R1. We appreciate the drafting team’s consideration in Attachment 1 to allow a unit that has already verified its turbine/governor and load control and active power/frequency control models to be considered compliant. However, it is not clear how this helps. How does the Generator Owner demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff be sufficient? Will the regional entities be willing to validate that they have confirmed regional criteria? We do not believe the VRF Requirement R5 should have a Medium VRF. It is an administrative requirement that is focused on notifying the Generator Owner as to the suitability of the model they provided. All of the measurements use language that sounds like a requirement and is not consistent with language used in any other NERC standard. They all use “must include”. It is more typical to use “shall demonstrate”, “shall make available”, etc. These measurements should be made consistent with other NERC standards. All of the measurements use language that requires proof of transmission of the communication. Some examples of the proof include data postal receipts, dated confirmation of facsimile, etc. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was

transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. Reports on email failures are separate reports. The Compliance Enforcement Authority section is not the latest approved language being used by NERC. We question the need to retain the “latest and previous turbine/governor and load control and active power/frequency control system model verification” as it seems excessive evidence retention. This could require Generator Owner’s to retain evidence for greater than twenty years which greatly exceeds the six-year audit cycle. Thus, it would not even be reviewable in an audit per the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Given that the cycle for compliance exceeds the audit cycle for Generator Owners of six years, we think the drafting team should work with NERC compliance to consider how the auditing of the standard will occur. Some small entities will have audits in which no generator will have to be verified. Should this requirement even be actively monitored or should it only require proof of compliance during investigations? We have identified several issues with the periodicity table in Attachment. First, the table is referred to as the periodicity table in the examples that accompany the unofficial comment form. It is not titled as such in the actual document. We believe a title would be appropriate for clarity. Second, Row 4 is not really a triggering event as the first column describes but rather a set of conditions that allow a Generator Owner to utilize an already verified unit model for a similar unit. Third, as written Row 5 only will apply when non-compliance occurs. For instance, Row 5 only applies when the 11 year period (10 year plus one year grace period) for Row 1 or Row 2 has been violated. We agree with the concept of that Row 5 presents in that a frequency event may not have occurred but the other Rows need to be clarified so that it does not present a non-compliance. Fourth, the first part of row 10 is also not really a triggering event but an exception.
No
We disagree with the need to include Blackstart Resources within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during a restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power

system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies the standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system.
Yes
We believe it is reasonable to include examples of satisfactory evidence. It helps to highlight the intent of the drafting team.
We do not believe Requirement R2 as written accomplishes the reliability purpose. Isn’t the purpose of R2 to compel registered entities to re-verify coordination every five years along with changes to “systems, equipment or setting changes” within 90 days? We do not believe “shall verify the existence of coordination” accomplishes this. We believe that it only compels the registered entity to verify the coordination was performed at some point. It does not compel the entity to verify that coordination reflects current conditions such as Protection System settings. We suggest changing “shall verify the existence of coordination” to “shall coordinate”. Furthermore, we think some of the confusion could be eliminated by including the five-year periodicity in Requirement R1 and focusing Requirement R2 on system and equipment changes. Section D.1.1 needs to be updated to reflect that latest approved language for the Compliance Enforcement Authority. The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the “verify the existence of the coordination” from Requirement R2. Requirement R1 uses “shall coordinate”. We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise

this to a High VRF.
Group
Puget Sound Energy
Tom Flynn
Puget Sound Energy
Yes
Yes
Yes
Very rarely will you get to the capability curve when testing real and reactive power. There is almost always a protective limit or you exceed 105% voltage. NERC does not specify what will prevent you from reaching maximum VAR output, so we assume that is up to the testing engineer.
Yes
No
This periodicity would ideally be the same as MOD 25 and MOD 26 since this testing, at least in the WECC region, is all done at the same time. Also it is not clear to find the ten year re-test requirement in Attachment 1, in fact it just seems inferred. If it is a ten year re-testing requirement, it should be more clearly stated in one of the requirements.
Yes
None
Yes
Yes
None
Individual
Ken Wofford
Georgia Transmission Corporation
Yes
Yes
Yes
No

Why not model what was tested?
No
We agree with the SERC DRS that the terminology in Attachment 1 be reviewed for consistency. Should the "and's" be "or's"? ("Turbine/governor and load control and active power/frequency control")
No
This is a MOD 25 question
Some of the requirements within this standard are confusing.
Group
Western Electricity Coordinating Council
Steve Rueckert
WECC
Yes
Yes
Yes
Measure M1 specifically references corrections for ambient conditions as part of the evidence required, but Requirement R1 does not specifically call out corrections for ambient conditions. The only reference to corrections for ambient condistions is in Attachment 1. For consistency it seems the Requirement detail and the Measure detail should be the same. The Lower and Moderate VSLs for R1 both include missing 33 percent of the data in the condition identified after the first OR in the VSL. If an entity was missing exactly 33 percent of the required data, it would not be possible to identify an appropriate VSL. WECC Staff recommends the use of the identifiers "less than or equal to" and "more than" to resolve the issue, and recommends that clarification be extended to the rest of this section of the VSLs for R1. The section of the VSLs for R3 that use percentages as the identifier should use "more than" and "less than or equal to" qualifiers.
The purpose statement appears to have an unnecessary word "that" immediately preceding the word accurately. After discussions with members of the drafting team WECC staff understands that the intent of the sub-sub-bullets in the applicability sections is intended to require that individual units greater than 20 MVA at generating plants greater than the identified Interconnection minimum be represented individually, while units less than 20 MVA at generating plants greater than the identified Interconnection minimum be represented as an equivalent, but

WECC staff does not believe that intent is clearly reflected in the words in the sub-sub bullets. The sub-sub bullets in the applicability section use both “consisting of” (4.2.1) and “comprised of” (4.2.3) and use “consisting comprised of” in 4.2.2. The language should be consistent and the grammatical error in 4.2.2 should be corrected. The Severe VSL for R2 includes providing required models more than 90 days late and also includes not providing models. It is not necessary to include the part about not providing models. If models are never provided, they are more than 90 days late. The VSLs for R5 should use “less than or equal to” rather than just “less than” in the sections identifying how many days late the written response was provided.

See additional comments received:

Kansas City Power & Light attached

Additional Comments Received
Kansas City Power & Light

1. **The GVSDT has revised MOD-025-2 by splitting Requirement R1 into two requirements that allow for separate testing for real and reactive power. A paragraph was added to the start of Attachment 1 that further explains this point. Do you agree with this revision? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

   Comments:

2. **The GVSDT clarified the applicability of this standard to synchronous condensers greater than 20 MVA (nameplate rating). Do you agree with this applicability? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

   Comments:

3. **The GVSDT clarified that the data is to be submitted to the Transmission Planner by the Generator Owner or Transmission Owner. Do you agree with this? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

   Comments:

4. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-025-2?**

   Comments: Should replace “bulk power system” with “Bulk Electric System”. Use of “bulk power system” is ambiguous where as “Bulk Electric System” is fully defined.

5. **The GVSDT has included partial load rejection testing in Part 2.1.1 subject to the conditions specified in footnote 5 (differences between the control mode tested and the final simulation model must be taken into account). Do you agree with the inclusion and footnote 5? If not, please explain in the comment area below.**

   ☒ Yes

☐ No

Comments:

6. **The GVSDT has provided guidance on the periodicity aspects of Attachment 1. Do you agree? If not, please explain in the comment area below.**

☒ Yes

☐ No

Comments:

7. **The GVSDT has address units which are always base loaded (by definition a base loaded unit is considered verified). This provides an exemption from verification for base load units. Do you agree? If not, please explain in the comment area below.**

☒ Yes

☐ No

Comments:

8. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-027-1?**

Comments: Should replace “bulk power system” with “Bulk Electric System”. Use of “bulk power system” is ambiguous where as “Bulk Electric System” is fully defined.

9. **The GVSDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 20 MVA. The standard applies to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 20MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the comment area below.**

☒ Yes

☐ No

Comments:

10. **The GVSDT revised section G based on stakeholders’ comments to provide clarity and to indicate that the items listed are examples of coordination and that entities may provide “Equivalent tables or other evidence.” Do you agree with the revisions to Section G? If not, please explain in the comment area below.**

☐ Yes

☒ No

Comments: This assumes that the auditor will have the protection skills and knowledge necessary to confirm that "other evidence" is equivalent to the plots shown in the attachment one examples.

11. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-019-1?**

Comments: Applicability section states any generator regardless of size that is a black start resource. This standard should not be applicable to black start diesel generators.
R2 requires verification every five years. This standard should only require initial verification during the five year implementation period. After the initial verification, no further verification should be required unless system or equipment changes dictate the need to make setting changes and re-verify.

Consideration of Comments

Generator Verification – Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the proposed revisions to MOD-025-2, MOD-027-1 and PRC-019-1. These standards were posted for a 45-day public comment period from February 29, 2012 through April 16, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 57 sets of comments, including comments from approximately 159 different people from approximately 51 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at Mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. The GV SDT has revised MOD-025-2 by splitting Requirement R1 into two requirements that allow for separate testing for real and reactive power. A paragraph was added to the start of Attachment 1 that further explains this point. Do you agree with this revision? If not, please explain in the comment area below. 14
2. The GV SDT clarified the applicability of this standard to synchronous condensers greater than 20 MVA (nameplate rating). Do you agree with this applicability? If not, please explain in the comment area below. 29
3. The GV SDT clarified that the data is to be submitted to the Transmission Planner by the Generator Owner or Transmission Owner. Do you agree with this? If not, please explain in the comment area below. 44
4. Do you have any other comment, not expressed in questions above, for the GV SDT regarding MOD-025-2? 52
5. The GVSDT has included partial load rejection testing in Part 2.1.1 subject to the conditions specified in footnote 5 (differences between the control mode tested and the final simulation model must be taken into account). Do you agree with the inclusion and footnote 5? If not, please explain in the comment area below. 140
6. The GVSDT has provided guidance on the periodicity aspects of Attachment 1. Do you agree? If not, please explain in the comment area below. 162
7. The GVSDT has address units which are always base loaded (by definition a base loaded unit is considered verified). This provides an exemption from verification for base load units. Do you agree? If not, please explain in the comment area below. 183
8. Do you have any other comment, not expressed in questions above, for the GV SDT regarding MOD-027-2? 198
9. The GVSDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 20 MVA. The standard applies to generating units/facilities that meet the compliance registry riteria and to synchronous condensers rated 20MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the comment area below. 273
10. The GVSDT revised section G based on stakeholders' comments to provide clarity and to indicate that the items listed are examples of coordination and that entities may provide "Equivalent tables or other evidence." Do you agree with the revisions to Section G? If not, please explain in the comment area below. 285

11. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-019-1? 292

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	David Thorne	Pepco Holdings Inc and Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Chantel Haswell	FPL Group, Inc.	NPCC	5
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1
11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
17.	Brian Robinson	Utility Services	NPCC	8
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Valerie Pinamonti	AEP	SPP	1, 3, 5
4.	Michelle Corely	CLECO	SPP	1, 3, 5
5.	Mahmood Safi	OPPD	SPP	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	David Thompson (Chair) ; Joe Spencer (SERC staff)	SERC Generation Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Thompson -chair	TVA	SERC	
2.	Hamid Zakery	Calpine Corp.	SERC	
3.	Tom Higgins	Southern Co.	SERC	

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

4. Terry Crawley	Southern Co.	SERC	
5. Bill Shultz	Southern Co.	SERC	
6. Kumar Mani	Progress Energy	SERC	
7. Paul Camilletti	Santee Cooper	SERC	
8. Dale Goodwine	Duke Energy	SERC	
9. Sam Dwyer	Ameren	SERC	
10. Joe Spencer	SERC	SERC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	John O'Connor (chair) ; Joe Spencer (SERC staff)	SERC Dynamic Review Subcommittee (DRS)										X

Additional Member	Additional Organization	Region	Segment Selection
1. Peng Yu	Entergy	SERC	
2. Tom Cain	TVA	SERC	
3. Bobby Jones	Southern Co.	SERC	
4. Warren Whitson	Southern Co.	SERC	
5. Robbie Bottoms	TVA	SERC	
6. Art Brown	Santee Cooper	SERC	
7. John O'Connor	Progress Energy	SERC	
8. Rick Foster	Ameren	SERC	
9. Sharma Kolluri	Entergy	SERC	
10. Joe Spencer	SERC	SERC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Karl	Fraughten	WECC	1
2. Tanner	Brier	WECC	1, 3, 5, 6
3. James	Burns	WECC	1
4. Don	Watkins	WECC	1
5. John	Haner	WECC	1
6. Dmitry	Kosterev	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jose Landeros	IID	WECC	1, 3, 4, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
2.	Cathy Breatz	IID	WECC	1, 3, 4, 5, 6
3.	Henryk Olstowski	IID	WECC	1, 3, 4, 5, 6
4.	Christopher Reyes	IID	WECC	1, 3, 4, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Paul Camilletti	Santee Cooper	SERC	5
3.	Rene Free	Santee Cooper	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Mike Garton	Dominion- NERC Compliance Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	NERC Compliance Policy	NPCC	6
2.	Louis Slade	NERC Compliance Policy	SERC	5
3.	Michael Crowley	Electric Transmission	SERC	1, 3
4.	Sean Iseminger	Fossil & Hydro	SERC	6
5.	Jeff Bailey	Nuclear	MRO	6
6.	Chip Humphrey	Fossil & Hydro	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Chang Choi	Tacoma Power	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4
3.	Claire Lloyd	Tacoma Public Utilities	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	B. Orians	FE	RFC	5
2.	E. Baznik	FE	RFC	1
3.	K. Dresner	FE	RFC	5
4.	L. Robinson	FE	RFC	5
5.	M. McLean	FE	RFC	1
6.	D. Hohlbaugh	FE	RFC	
7.	L. Raczkowski	FE	RFC	

Group/Individual	Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
12. Group	Charles W. Long	SERC Planning Standards Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NC Electric Membership Corporation	SERC	1
3.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
4.	Philip Kleckley	SC Electric & Gas Company	SERC	1
5.	Pat Huntley	SERC Reliability Corporation	SERC	10
6.	Bob Jones	Southern Company Services	SERC	1
7.	Darrin Church	TVA	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	James Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Annette M. Bannon	PPL					X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Heimbach	PPL EnergyPlus, LLC	MRO	6
2.	Annette Bannon	PPL Generation for its NERC Registered Entities	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	William Gallagher	Transmission Access Policy Study Group	X		X	X	X	X				

No additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Jason Marshall	ACES Power Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5
2.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
3.	Mohan Sachdeva	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Group	Tom Flynn	Puget Sound Energy					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Denise Lietz	Puget Sound Energy	WECC	1
2.	Erin Apperson	Puget Sound Energy	WECC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Steve Rueckert	Western Electricity Coordinating Council										X

No additional members listed.

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Individual	David Thompson	Tennessee Valley Authority - GO/GOP	X		X		X	X				
20.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
21.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
22.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
23.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
24.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				
25.	Individual	Dan Roethemeyer	Dynegy					X					
26.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
27.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	S. Tekala	SRP	X				X				X	
32.	Individual	John Seelke	Public Service Enterprise Group (PSEG)	X		X		X					
33.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
34.	Individual	David Youngblood	Luminant Power					X					
35.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
36.	Individual	Jack Stamper	Public Utility District No. 1 of Clark County	X									
37.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
38.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
39.	Individual	Anthony Jablonski	ReliabilityFirst										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Kathleen Goodman	ISO New England Inc.		X								
42.	Individual	Mark B Thompson	Alberta Electric System Operator		X								
43.	Individual	Darryl Curtis	Oncor Electric Delivery Company	X									
44.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
45.	Individual	Dennis Sismaet	Seattle City Light						X				
46.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
47.	Individual	Thad Ness	American Electric Power	X		X		X	X				
48.	Individual	John Bee	Exelon	X		X		X					
49.	Individual	Don Jones	Texas Reliability Entity										X
50.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
51.	Individual	Matthew Pacobit	AECI					X					
52.	Individual	Randall McCamish	City of Vero	X		X							
53.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
54.	Individual	Michael Goggin	American Wind Energy Association								X		
55.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
56.	Individual	Ken Wofford	Georgia Transmission Corporation	X									
57.	Individual	Michael Gammon	Kansas City Power & Light										

MOD-025 Overall Summary Consideration: Stakeholders provided many suggestions for improvements to the language of the standard.

The majority of stakeholders agree with splitting the requirements as noted in the revised standard. The majority of the comments appear to be caused by confusion concerning what exactly is meant by separate testing as stated in Attachment 1. This seems to be caused by the fact that the Reactive Power verification requires Reactive Power data to be taken at several different Real Power operating levels. The intent of the standard drafting team is to allow verification of Real and Reactive Power at the same time if desired by the Generator Owner. This is not required. If the generator owner desires, they may do the two verifications at separate time. It is the opinion of the drafting team that since one of the operating points required for the Reactive Power verification is one with the Real Power output at the expected maximum, that it would be a simple and efficient method to use that operating point as the Real Power verification also.

The majority of commenters agree with the applicability to synchronous condensers greater than 20 MVA. Some commenters suggested that Synchronous Condensers do not have a full capability curve and therefore, do not need to be tested at four points. While the GVSDT agrees that synchronous condensers do not have a typical capability curve, nor do they need one, a verification of the capability is needed similar to the verification of synchronous generators. We have added Note 5 to Attachment 1 to clarify this:

> **"Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output."**

A couple of stakeholders suggested having the applicability threshold increase from 20 MVA to 100 MVA. The GVSDT respectfully disagrees with regard to the 20 MVA threshold and believes that the same MVA threshold used for reactive capability of synchronous generators should apply to synchronous condensers.

Most stakeholders agree with having the verification data submitted to the Transmission Planner. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator, Balancing Authority or Planning Authority (Coordinator). As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the Operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (v5, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

The GVSDT has not revised the requirement with which continues to require the data be submitted to the Transmission Planner.

Several stakeholders disagree with the use of "bulk power system" in the applicability. The GVSDT has revised this to use the term "Bulk Electric System" instead. Concerns were raised regarding the verification schedule for entities that own five or fewer units. The GVSDT removed Sections 5.1.1 and 5.2.1. Entities that own one unit will be required to verify their unit within two years. Entities that own two units will be required to verify one unit within two years and both units within three years.

The GVSDT received several comments regarding the language in Attachment 1. As a result the GVSDT restructured item 2 of Attachment 1:

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

Some commenters had questions regarding Section 5.3 regarding wind farms. The GVSDT acknowledges that this statement was placed in the standard as an explanation and is not appropriate to be included as section 5.3. This information was expanded and included as a footnote rather than section 5.3:

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

1. **The GV SDT has revised MOD-025-2 by splitting Requirement R1 into two requirements that allow for separate testing for real and reactive power. A paragraph was added to the start of Attachment 1 that further explains this point. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: The majority of stakeholders agree with splitting the requirements as noted in the revised standard. The majority of the comments appear to be caused by confusion concerning what exactly is meant by separate testing as stated in Attachment 1. This seems to be caused by the fact that the Reactive Power verification requires Reactive Power data to be taken at several different Real Power operating levels. The intent of the standard drafting team is to allow verification of Real and Reactive Power at the same time if desired by the Generator Owner. This is not required. If the generator owner desires, they may do the two verifications at separate time. It is the opinion of the drafting team that since one of the operating points required for the Reactive Power verification is one with the Real Power output at the expected maximum, that it would be a simple and efficient method to use that operating point as the Real Power verification also.

Organization	Yes or No	Question 1 Comment
Southwest Transmission Cooperative, Inc.	Negative	1. While we agree with the intent, we believe that Parts 1.2 and 2.2 collectively limit the tests to be no further than 90 days apart. Both parts state that Attachment 2 or another form that contains the same information must be completed within 90 calendar days of the staged test or date the operational data is selected. Since both have real and reactive power entries, can the form be considered completed without both sets of data? If the SDT intends for these real and reactive power tests to be completed greater 90 days apart, some additional clarification needs to be made to Part 1.2 and 2.2. Perhaps a note at the beginning of Attachment 2 explaining that MVAr will not be completed for a real power test and MVA will not be completed for a reactive power test will be sufficient. 2. What if a wind farm has more than two sites? Why is it specific to a single technology?

Organization	Yes or No	Question 1 Comment
		3. We disagree with testing a unit with capability to operate in synchronous condenser mode in that mode. Most likely the unit would only operate in this mode in an emergency situation. Thus, it does not make sense to operate a unit in an emergency mode for a test. 4. We do not agree with adding a last verification data column in Attachment. This only causes confusion. Will it be clear to auditors that the last verification data column is to remain blank for the initial verification or will we end up with a similar situation to the Protection System Maintenance and Testing standard where auditors required evidence from before the enforcement date of standards? Ultimately, the NERC CEO had to overrule this situation. Furthermore, it creates additional work to transfer data from a previous verification test to the current test when the past sheet could simply be retained. 5. Finally, it causes confusion with the data retention section because the data behind Attachment 2 must be retained. Is this intended to be only the latest verification or does it include the last verification? Item 2 of the verification specifications for applicable Facilities in Attachment 1 conflicts with Parts 1.2, 2.2, and 3.2 of the Requirements R1, R2 and R3. The attachment states that historical data going back two years can be used. However, the requirement parts state that the data must be submitted with 90 days to the Transmission Planner. That would appear to limit the historical data to 90 days. The attachment never makes it clear if you can switch between operational data and staged verification from one test to another. The confusion is caused by the separate listing of periodicities in items 1 and 2 under the "Periodicity for conducting a new verification" section. A close reading of the two items shows they are identical but listed separately to make the statement about listing

Organization	Yes or No	Question 1 Comment
		the “earliest date of those dates” for the operational data. We suggest combining item 1 and 2 together will help eliminate this confusion. We disagree with the need to conduct another staged test rather than using operational data as specified in Attachment I subsection 2 in the “Verification specifications for applicable Facilities:” section. If operational data can be used to satisfactorily verify the unit’s real and reactive power output, it should always be allowed to avoid the need for a staged test.

Response: The GVSDT thanks you for your comment.

1. **Sections R1.1.1 and R2.2.1 require that the verifications be performed and sections R1.1.2 and R2.2.2 require that the data be reported within 90 days of the date the verification is performed if for a staged test, or the date that the data is selected if the GO is utilizing operational data. The requirement is written in this way to allow the GP the flexibility of choosing either operational data (the actual date of collection of this operational data may be in the past, hence the requirement to report it within 90 days of the date of SELECTION of the data) or to stage a specific test to meet the requirement. If a GO decides to use two separate operational data points for the real and reactive verifications, then each attachment 2 might have some blank spots. The Attachment 2 is only a convenience for reporting, and GOs are free to use any form that captures the same information. If one is performing real power verification, then reactive power would not be reported. If one is performing a reactive power test, one must record more than one point. These points are defined by both real and reactive power, so both must be recorded. Again, the language was specifically crafted to allow the GO to perform both verifications at the same time if they choose, but this is not required. If a GO chooses to perform the verifications together, at the same time, then a single Attachment 2 is sufficient for both.**
2. **Wind Farms are a unique situation for compliance with MOD-025. The intent of Section 5.3 was to add clarity and provide an example of how to assess compliance for wind farms. The GVSDT has removed this section and added a footnote to clarify the issue further.**

    [1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Organization	Yes or No	Question 1 Comment
3. The standard is applicable to Synchronous Condensers greater than 20 MVA because they are important reactive resources. These are devices that normally operate as synchronous condensers, so they are not operating in an emergency mode. Perhaps the commenter refers to certain hydro units that can be operated at 0 power factor. These would not be considered synchronous condensers under the standard. 4. The drafting team appreciates your comment, as many members are aware of the situation you cite. The team cannot predict the behavior of auditors. The last verifications date column was added to avoid potential confusion with the use of operational data. When operational data is used, the last verification date may not match the date the operational data was selected and submitted, thus the information was added to simplify the determination of periodicity. 5. We do not see a conflict. The requirement simply states that the data must be SUBMITTED within 90 days of either a staged test or the date that operational data was SELECTED. The attachment informs entities that operational data can come from within a two year period prior to the verification date. The verification date for verification by operational data is the date that the operational data was SELECTED, not the date that the operational data was recorded. The GVSDT recognizes that the language is somewhat complex, however, it is the best we have that still allows the flexibility to use either operational data or a staged test. The GVSDT would welcome specific suggestions for improved language that preserves this intent. The language in Attachment 1 section 2 requires that the first test be a staged test. This is intended to prevent the use of operational data points that do not validate at least 50% of the associated D curve capability from being used as the benchmark for future verifications. Once an initial staged test to the appropriate level is completed, use of operational data going forward is allowed.		
Luminant Energy	Negative	See comments submitted by Luminant Energy. VOTE NO based on the extensive comments made that deleted items in Attachment 1 and 2.
Response: The GVSDT thanks you for your comment. Please see the response to Luminant Energy's comments.		
Northeast Power Coordinating Council	No	1. Attachment 1 requires a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% that is expected to last more than 6 months within 12 months. This is an excessive period of time for a generator to be providing less than expected Real or Reactive power output.

Organization	Yes or No	Question 1 Comment
		2. Also, Attachment 1 requires staged verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.). 3. The data requested in this Standard will verify a generator's capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data for both under-excited and over-excited field conditions will result in 4 specific data points that can assist TP's in system studies. The GO can obtain this data by planning on doing the maximum lagging and leading tests when system conditions allow to measure the 4 specific data points desired. 4. "Separate tests" are not explained except for the statement "separate testing is allowed for this standard" which is in Attachment 1. What constitutes "separate testing"?

Response: The GVSDT thanks you for your comment.

1. The GVSDT does not feel that this is excessive. The planning function is typically performed on an annual basis. There are real time operating reporting requirements for short term issues

2. The standard requires verification every 5 years. The first verification must be by a staged test, subsequent verifications can be either by staged test or reporting of operational data.

3. As the commenter notes, the standard requires Reactive Power Verification at different points. The required Real Power levels are part of the Reactive Power verification. This is why the standard allows Generator Owners to perform both Real and

Organization	Yes or No	Question 1 Comment
Reactive Power verification at the same time if they choose. It does not require that both be performed at the same time, primarily to allow maximum flexibility in the case of verification by operational data. If one performs the Reactive Power verification by itself, one must still reach the required Real Power operating points as described in the Attachment 1 section 2, so there is no harm in performing the test separately. There is a significant level of experience performing these tests among the members of the drafting team. It is not always possible to reach the D curve levels due to various conditions not related to the generating equipment performance, and for this reason there is no requirement to reach the D curve rating. The standard requires that the verification be performed to the level allowed by system conditions. 4. Separate testing is the performance of the real and reactive verifications at different time. It is allowed, but not required.		
PPL	No	Suggest changing “Intended” to “preferred” in the Att. 1 statement, “It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”
Response: The GVSDT thanks you for your comment. The GVSDT sees no difference from a reliability standpoint in performing the two tests together or separately, since the same data is collected. One is not preferred over the other, and we stand by the word intended because it is more time efficient to do both together.		
ACES Power Standards Collaborators	No	While we agree with the intent, we believe that Parts 1.2 and 2.2 collectively limit the tests to be no further than 90 days apart. Both parts state that Attachment 2 or another form that contains the same information must be completed within 90 calendar days of the staged test or date the operational data is selected. Since both have real and reactive power entries, can the form be considered completed without both sets of data? If the SDT intends for these real and reactive power tests to be completed greater 90 days apart, some additional clarification needs to be made to Part 1.2 and 2.2. Perhaps a note at the beginning of Attachment 2 explaining that MVAr will not be completed for a real power test and MVA will not be completed for a reactive power test will be sufficient.
Response: The GVSDT thanks you for your comment. The Reactive Power test requires Real Power data also. The Real Power		

Organization	Yes or No	Question 1 Comment
test does not require Reactive Power Data. The Real Power and Reactive Power tests may have different verification dates, so the GVSDT does not believe that the requirement limits them to be no more than 90 days apart. The data must only be reported within 90 days of the verification.		
Consolidated Edison Co. of NY, Inc.	No	o The data requested in this Standard will verify a generators capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data both under and over excited field conditions will result in 4 specific data points that can assist TP's in system studies. For example, the GO can obtain this data by: o The maximum lagging and then leading test at full load may be performed during a high load day to obtain two data points. o The maximum lagging and then leading test at minimum load may be performed during the evening to two data points. o We could not find a paragraph explaining separate tests except for the statement "separate testing is allowed for this standard". So no, we don't agree with this revision. Attachment 1 requires verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.).
Response: The GVSDT thanks you for your comment. Please see the response to the Northeast Power Coordinating Council comments.		
SRP	No	Real Power tests were performed at the same time as Laod Reactive Power testing in the past and plotted on the generator"s capability curves. What would be gained by conducting two separate tests?

Organization	Yes or No	Question 1 Comment
Response: The GVSDT thanks you for your comment. Two separate tests are not required, it is allowed if desired by the Generator Owner.		
Public Service Enterprise Group (PSEG)	No	In splitting R1 into two requirements, the R2 erroneously refers to "Real Power"; this should be "Reactive Power." The first sentence in added paragraph Attachment 1 regarding separate testing of Real and Reactive Power testing should be rewritten. The term "Load" as used does not conform to the Glossary definition of "Load," which is "An end-use device or customer that receives power from the electric system." The only combined testing on Real and Reactive Power applies to sections 2.1 and 2.2 in Attachment 1 where Real Power is tested. Therefore, the added sentence should be rewritten as follows: "It is intended that Real Power testing in sections 2.1 and 2.2 be performed at the same time as Reactive Power testing; however separate testing is allowed for this standard."
Response: The GVSDT thanks you for your comment. The commenter is correct that R2 should refer to Reactive Power, the error will be corrected. **The GVSDT agrees, and the word 'Load' will be eliminated and replaced with "Real Power".**		
ISO New England Inc.	No	Attachment 1 does not require a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% for up to 12 months. This is too long a period for a generator to be providing less than expected power output.
Response: The GVSDT thanks you for your comment. The time period is consistent with the planning function, which is typically performed on an annual basis. The real time operating standards already require more immediate reporting of unit limitations.		

Organization	Yes or No	Question 1 Comment
TransAlta Centralia Generation LLC	No	Do not agree to Attachment 1 item 2.2 and 2.3. Refer comments below: 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Typically, the maximum overexcited and under-excited reactive capability is tested at the Rated or full Real Power output of generator, not at the minimum Real Power output of generator. 2.3. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour. Please verify the reason for a minimum of one continuous hour.
Response: The GVSDT thanks you for your comment, but is unable to respond since you have not provided any information on what you don't agree with in Attachment 1 2.2 and 2.3 or why.		
Seattle City Light	No	Attachment 1 "Periodicity for conducting a new verification:" Frequency of tests should correlate better with MOD-026 and MOD-027, which is once every 10 years.
Response: The GVSDT thanks you for your comment. The drafting team felt that 5 years was appropriate for this standard in order to catch any equipment issues that might develop. The longer periodicity for MOD-026 and MOD-027 reflects the greater complexity involved with performing those verifications.		
AECI	No	I believe that a one continuous hour test for reactive testing will not increase reliability. Most units are not used for long periods of time for reactive power. I am also worried about damage due to High winding temperatures during this test.
Response: The GVSDT thanks you for your comment. There is no requirement to exceed any generating unit limits, such as winding temperatures, during the verifications. One continuous hour was established as a minimum time for verification that		

Organization	Yes or No	Question 1 Comment
there are no equipment related issues with operating at the verification levels.		
Seattle City Light	No	Attachment 1 “Periodicity for conducting a new verification:” Frequency of tests should correlate better with MOD-026 and MOD-027, which is once every 10 years.
Response: The GVSDT thanks you for your comment. The drafting team felt that 5 years was appropriate for this standard in order to catch any equipment issues that might develop. The longer periodicity for MOD-026 and MOD-027 reflects the greater complexity involved with performing those verifications.		
City of Vero	No	
Dominion- NERC Compliance Policy	Yes	Dominion agrees with splitting Requirement R1; but notes that Requirement R2 should be changed from “Real Power Capability” to “Reactive Power Capability.” Additionally, Requirement R3 should be changed from “Real Power Capability” to “Reactive Power Capability.”
Response: The GVSDT thanks you for your comment. You are correct and the standard has been updated to show the corrections.		
SERC Generation Subcommittee	Yes	However, see our response to Question #4.
Response: The GVSDT thanks you for your comment. Please see responses to question 4.		
Southern Company	Yes	a) The method of reactive power capability determination described in "Note 2" of Attachment 1 should be included as an allowable third (3rd) method of reactive power capability verification. (as an alternative to using operational data or staged testing) b) Any verification specifications listed on Attachment 1 that merely repeat the line items of data requirements shown on Attachment 2 should be eliminated - they are not necessary in both locations.

Organization	Yes or No	Question 1 Comment
Response: The GVSDT thanks you for your comment. a)The GVSDT does not believe that calculations are an appropriate method of verification as they do not show anything about equipment condition or prove that equipment will work as designed. **b) The GVSDT believes that this adds clarity, and represents very little additional effort.**		
Ingleside Cogeneration LP	Yes	Even if the requirements are somewhat redundant, there are a number of important differences between Real and Reactive Power validations. In addition, there is a need to allow Generator Owners to address each separately if they should so choose. For example, a Real Power validation may be easily handled through actual operations data, while Reactive Power validations may need coordinated testing with the interconnected Transmission Operator. Under a single requirement, there is a risk that Compliance Authorities will assume that every test must be performed at the same time - using the same method.
Response: The GVSDT agrees and thanks you for your comment.		
Wisconsin Electric Power Company	Yes	Requirements R1.2 and R2.2 have data submittal dates for Real and Reactive Power verification values. The required timeframe of “90 calendar days” needs to be clarified when using historical operating data. For example, if a date of 180 days ago is selected for the verification, how can the data be required within 90 calendar days? The due date for a verification using historical data does not seem very meaningful.
Response: The GVSDT thanks you for your comment. The GVSDT agrees, and that is why the standard states in the requirements that the verification date for operational data verifications is the date that the operational data is SELECTED, not the date the operational data was RECORDED.		
Texas Reliability Entity	Yes	R1.2 - We suggest removing the phrase “date the data is recorded for a” and replace with “date of a”. It is not important to note the date on which the data is “recorded” but rather the date a staged test occurred. “Recorded”

Organization	Yes or No	Question 1 Comment
		could have different meanings - is it "recorded" when a Verification Data form or report is finalized internally or when PI Historian captures the SCADA data? Remove "or a form containing the same information as identified in Attachment 2" and change the verbiage on Form 2 ("changes may be made to this form"). If there is a form, require its use to promote consistency. Additional forms can be provided by the TP if needed to cover additional configurations.
Response: The GVSDT thanks you for your comment. The GVSDT believe that language is clear, and that the two situations that you note are differentiated by the fact that the word 'submitted' is used to describe when the data is sent to the Transmission Planner, the word 'recorded' describes when the staged test data is taken. Further, the word 'Selected' is used to describe the date that operational test data is chosen for us as verification data. Attachment 1 states that this operational data may come from anywhere in the two year period prior to its selection date.		
Duke Energy	Yes	However, see our response to Question #4.
Response: The GVSDT thanks you for your comment. Please see response to question 4.		
Tacoma Power	Yes	None
Southwest Power Pool Standards Development Team	Yes	
SERC Dynamic Review Subcommittee (DRS)	Yes	
Bonneville Power Administration	Yes	
Imperial Irrigation District (IID)	Yes	

Organization	Yes or No	Question 1 Comment
Santee Cooper	Yes	
FirstEnergy	Yes	
SERC Planning Standards Subcommittee	Yes	
Puget Sound Energy	Yes	
Western Electricity Coordinating Council	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Ameren	Yes	
Oncor Electric Delivery Company	Yes	
Cowlitz County PUD	Yes	
American Electric Power	Yes	
Exelon	Yes	
Entergy Services, Inc	Yes	
American Wind Energy Association	Yes	
Indiana Municipal Power Agency	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
Pepco Holdings Inc and Affiliates		No comment

2. The GV SDT clarified the applicability of this standard to synchronous condensers greater than 20 MVA (nameplate rating). Do you agree with this applicability? If not, please explain in the comment area below.

Summary Consideration: The majority of commenters agree with the applicability to synchronous condensers greater than 20 MVA.

Some commenters suggested that Synchronous Condensers do not have a full capability curve and therefore, do not need to be tested at four points. While the GVSDT agrees that synchronous condensers do not have a typical capability curve, nor do they need one, a verification of the capability is needed similar to the verification of synchronous generators. We have added Note 5 to Attachment 1 to clarify this:

> **"Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output."**

A couple of stakeholders suggested having the threshold increase from 20 MVA to 100 MVA. The GVSDT respectfully disagrees with regard to the 20 MVA cut-off and believes that the same MVA threshold used for reactive capability of synchronous generators should apply to synchronous condensers.

Other stakeholders disagreed with the applicability section referencing the "bulk power system." The GVSDT agrees and revised this to reference "Bulk Electric System."

Organization	Yes or No	Question 2 Comment
City of Green Cove Springs	Negative	Applicable Facilities could be simply those that are not Black-Start., simplifying the language considerably
Response: The GVSDT thanks you for your comment. The GVSDT believes that by simply saying "those that are not Black Start" in the Applicability/Facilities section that synchronous condensers would be excluded and smaller facilities that were not intended would be included. There was overwhelming support on the last posting to include synchronous condensers to this standard.		
Southwest Transmission Cooperative, Inc.	Negative	While we agree to limit the inclusion of synchronous condensers to 20 MVA, we disagree with two other aspects of the applicability. We disagree with inclusion of Blackstart Resources and applicability to the bulk power system. Blackstart Resources should not be included within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under

Organization	Yes or No	Question 2 Comment
		criterion III.c.3, the purpose of their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during the restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations.
Response: The GVSDT thanks you for your comment. The GV SDT removed blackstart units from the standard in the previous posting.		
Pepco Holdings Inc and Affiliates	No	Agree with the generating unit nameplate thresholds as defined in this standard and the compliance registry, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the

Organization	Yes or No	Question 2 Comment
		applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition. Of course, Synchronous condensers are not spelled out either in the Compliance Registry, or the BES definition, and therefore they will have to be addresses separately in 4.2.2 as “Individual Synchronous Condensers greater than 20MVA (gross nameplate rating) directly connected at the point of interconnection at 100kV or above. “
Response: The GVSDT thanks you for your comment. The SDT agrees and has replaced “bulk power system” with the defined term “BES”.		
Northeast Power Coordinating Council	No	The data requested in this Standard will verify a generator’s capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, synchronous condensers should be removed from MOD-025.
Consolidated Edison Co. of NY, Inc.	No	The data requested in this Standard will verify a generators capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, we recommend that synchronous condensers be removed from MOD-025.
Response: The GVSDT thanks you for your comment. While the GVSDT agrees that synchronous condensers do not have a typical capability curve, nor do they need one, a verification of the capability is needed similar to the verification of synchronous		

Organization	Yes or No	Question 2 Comment
generators. We have added Note 5 to Attachment 1 to clarify this: **"Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output."**		
SERC Generation Subcommittee	No	Clarification should be made on applicability. Does this apply only to stand-alone synchronous condensers, or are hydro units, that can be used in condensing mode, also included? Also, we believe that the 20 MVA cut-off rating is too low for this standard. We would suggest that the same threshold used in MOD 26 and 27 (100 MVA), be used. If necessary, the regions can set more restrictive thresholds.
Santee Cooper	No	Clarification should be made on applicability. Does this apply only to stand alone synchronous condensers, or are hydro units that can be used in condensing modes, also included. Also, we believe that the 20 MVA rating is too low for this standard. We would suggest that the same threshold as used in MOD 26 and 27 (100 MVA) be used. If necessary, the regions can set more restrictive thresholds.
Response: The GVSDT thanks you for your comment. The standard applies to both stand alone synchronous condensers and hydro units that can be used in condensing modes. The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator. The GVSDT respectfully disagrees with regard to the 20 MVA threshold and believes that the same MVA threshold used for reactive capability of synchronous generators should apply to synchronous condensers.		
SERC Dynamic Review Subcommittee (DRS)	No	In some cases there is no benefit to require testing of smaller units. The DRS recommends that units with nameplate ratings at or below 100 MVA (consistent with the MOD-027-1) be exempted from testing upon mutual agreement between the GO and Transmission Planner.
Response: The GVSDT thanks you for your comment. Due to the localized nature of voltage control the GVSDT feels it would be a mistake to classify Reactive Power testing the same as the Active Power/Frequency Control functions included in MOD-027-1. The		

Organization	Yes or No	Question 2 Comment
GVSDT does not have sufficient evidence to exempt generators that are included in the NERC Registry Criteria nor do we believe it is appropriate to exclude them.		
Florida Municipal Power Agency	No	FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that:BPS = BES + (protection and control systems covered by the standards)To parallel the Section 215 definition of BPS at (a)(1)"The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..."We have not heard from the BES definition team yet whether they will address this issue.A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element".To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn’t already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. The SDT agrees and has replaced references to "bulk power system" with the NERC defined term BES. The SDT disagrees that a synchronous condenser is a generator and the Transmission Owner could be removed from the Applicability because a significant number of synchronous condensers are owned by the Transmission Owner, not the Generator Owner.		
Transmission Access Policy Study Group	No	The SDT states that it "felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry Criteria and the BES definition." TAPS agrees that the standard should be consistent with the BES definition. Given that the MVA limits in the BES definition (and the Registry Criteria) may change, TAPS believes that the standard should not contain numerical limits. Moreover, the standard should be based on the BES definition, which delineates the elements subject to Reliability Standards, rather than on the Statement of Compliance Registry Criteria, which instead defines the entities that must comply with Reliability Standards. We believe that the SDT's concern about synchronous condensers can also be addressed more effectively without incorporating text from the current Registry Criteria. TAPS therefore suggests that the Applicable Facilities section be revised as follows: "For the purpose of this standard, the term, 'applicable Facility' shall mean 'BES generator,' except that a generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator's restoration plan is not an applicable Facility for the purpose of this standard. For the purpose of this standard, a synchronous condenser is treated as a generator."
Response: The GVSDT thanks you for your comment. The GVSDT at one point referred to the applicable units simply by those included in the Registry Criteria but was directed by NERC to state the numerical limits. If in the case where the BES definition or Registry Criteria definitions change, the" Applicability" can be reviewed and updated as necessary during the next standard revision.		
ACES Power Standards Collaborators	No	While we agree to limit the inclusion of synchronous condensers to 20 MVA, we disagree with two other aspects of the applicability.

Organization	Yes or No	Question 2 Comment
		1) We disagree with inclusion of Blackstart Resources and applicability to the bulk power system. Blackstart Resources should not be included within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, the purpose of their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during the restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. 2) The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete,

Organization	Yes or No	Question 2 Comment
		confusing and potentially applies that standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. 3) We also find section 5.3 regarding wind farm verification confusing. What is its purpose? What if a wind farm has more than two sites? Why is it specific to a single technology?
Response: The GVSDT thanks you for your comment. **1) The SDT removed blackstart units from this standard in the previous posting.** **2) The SDT has replaced "bulk power system" with the defined term "BES".** **3) The SDT has removed section 5.3 (Effective Date) and replaced it with a footnote as follows:** **1 Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.**		
Southern Company	No	a) The applicability threshold is too small. Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to individual unit size of 100 MVA for the Eastern Interconnection. b) We feel that machines able to run either as a synchronous condenser as well as a synchronous generator need only be validated in generator mode. It is unclear if the requirement for synchronous condensers is for machines with a single mode of operation. c) The individual unit size criterion value should equal the gross aggregate plant/ Facility threshold value.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 2 Comment
a) MOD-026-1 and MOD-027-1 verify models. PRC-019 coordinates limiters with protection and machine capabilities. MOD-025-1 verifies Real and Reactive capabilities. Although loosely related the purpose of each of these standards is different. The potential for stated capability to be different from the capability that can be verified is large. With this in mind, the GVSDT has no basis to exclude generators that are included in the Registry Criteria nor do we believe it is appropriate to do so. b) The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator. c) Changing the unit size criterion to make value to equal the gross aggregate plant/facility threshold value would effectively exempt a large portion of generation (all wind farms would be exempted for example). The GVSDT has no basis to exempt this much generation.		
ExxonMobil Research and Engineering	No	The SDT should clarify that a Synchronous Condenser is not a Synchronous Motor. Synchronous condensers are operated to provide Voltage Support to the bulk electric system through the production of VARS. A Synchronous Motor is theoretically the same piece of equipment with one exception; in a modern industrial electric distribution system, a Synchronous Motor's purpose is to drive a mechanical load while remaining VAR neutral (or closes to it). As written, industrial facilities that are registered as Generator Owners and operate large Synchronous Motors may be required to comply with this standard and be unable to comply with this standard due to the nature of the equipment that operates the Synchronous Motor's excitation system.
Response: The GVSDT thanks you for your comment. The GVSDT believes that a synchronous condenser and a synchronous motor are synchronous machines that are used for two different purposes. We believe this purpose is clear and there will be no confusion that the standard is applicable to synchronous condensers and not synchronous motors. It is believed that there are no synchronous motors (with the exception of those motor/generators used in pumped storage facilities) that are directly connected to the BES and they would, therefore, not be included in the applicability for MOD-025-2.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP believes that MOD-025-2 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since

Organization	Yes or No	Question 2 Comment
		synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System - and this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of the BES takes effect.
Response: The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers during the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2."		
Public Service Enterprise Group (PSEG)	No	In the Background material on the Comment form for MOD-026-2 and PRC-024-2, the following statement is included for MOD-026-2:"The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers."If synchronous condensers are

Organization	Yes or No	Question 2 Comment
		not currently addressed in the NERC Registry Criteria, they should not be included in the either MOD-025-2 or PRC-019-1.
Response: The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2."		
City of Vero	No	FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards)To parallel the Section 215 definition of BPS at (a)(1)"The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..."We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT

Organization	Yes or No	Question 2 Comment
		wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn't already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard.
Response: The GVSDT thanks you for your comment. The SDT agrees and has replaced references to "bulk power system" with the NERC defined term BES. The SDT disagrees that a synchronous condenser is a generator and the Transmission Owner could be removed from the Applicability because a significant number of synchronous condensers are owned by the Transmission Owner, not the Generator Owner.		
Texas Reliability Entity	Yes	Attachment 1, item 3.2: Is there a requirement for a voltage schedule for a synchronous condenser? Also, if there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. Attachment 2 does not necessarily include Synchronous Condensers.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has added the words "if applicable" to item 3.2. While Attachment 2 does not necessarily include synchronous condensers it does not exclude them either. The GVSDT has revised Attachment 2 to specifically include synchronous condensers.		
Tacoma Power	Yes	None
Southwest Power Pool Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Dominion- NERC Compliance Policy	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
SERC Planning Standards Subcommittee	Yes	
PPL	Yes	
Puget Sound Energy	Yes	
Western Electricity Coordinating Council	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Wisconsin Electric Power Company	Yes	
Ameren	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
Cowlitz County PUD	Yes	
American Electric Power	Yes	
Exelon	Yes	

Organization	Yes or No	Question 2 Comment
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
Imperial Irrigation District (IID)		Not applicable to IID - abstained
Indiana Municipal Power Agency		no comment

3. The GV SDT clarified that the data is to be submitted to the Transmission Planner by the Generator Owner or Transmission Owner. Do you agree with this? If not, please explain in the comment area below.

Summary Consideration: Most stakeholders agree with having the verification data submitted to the Transmission Planner. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator, Balancing Authority or Planning Authority (Coordinator). As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the Operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (v5, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

The GVSDT has not revised the requirement with which continues to require the data be submitted to the Transmission Planner.

Organization	Yes or No	Question 3 Comment
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.

Organization	Yes or No	Question 3 Comment
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.
Oncor Electric Delivery Company	No	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.

Response: The GVSDT thanks you for your comment. Please see Summary Consideration for question 2 from the previous posting. That response states in part: "Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the Operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (v5, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

Organization	Yes or No	Question 3 Comment
6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers. **The GVSDT has not revised the requirement with respect to submitting the data to the Transmission Planner. The requirement continues to require the data be submitted to the Transmission Planner."**		
Northeast Power Coordinating Council	No	The Reliability Coordinator is the entity that should receive this data. There are instances where a number of entities are registered as Transmission Planners. To avoid confusion this data should be submitted to a single entity who will then distribute the data. Transmission Planner should be added to the Applicability Section 4.1 Functional Entities.
Response: The GVSDT thanks you for your comment. The GVSDT believes that since the Transmission Planner does not have any actions under the standard except receiving the data, addition of the Transmission Planner is not needed. An overwhelming majority of the commenters concurred with the Transmission Planner as the entity to receive the data and therefore, the GVSDT does not propose a change.		
Public Service Enterprise Group (PSEG)	No	Transmission Operators should also be provided the data.
Response: The GVSDT thanks you for your comment. In accordance with the NERC reliability function model, Transmission Planners are required to report its planning results to Transmission Operators and because of this, the GVSDT does not believe the Transmission Operators need to be added to this standard.		
ISO New England Inc.	No	We feel that the Reliability Coordinator is the appropriate entity to receive this data. In our area a number of entities are registered as Transmission Planners, to avoid confusion this data should be submitted to a single entity who will then distribute the data.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. An overwhelming majority of the commenters concurred with the Transmission Planner as the entity to receive the data and therefore, the GVSDT does not propose a change. In accordance with the NERC reliability function model, Transmission Planners are required to report its planning results to Reliability Coordinators and because of this, the GVSDT does not believe the Transmission Operators need to be added to this standard.		
TransAlta Centralia Generation LLC	No	In some cases, the data at the interconnection point (such as the high side of generator step-up transformer) may not come directly from GO as the measuring instrumentation may not be owned by the GO
Response: The GVSDT thanks you for your comment. Since the bulk of the information (and in many cases all of the information) needed comes directly from the GO, the GVSDT believes that the GO is the correct entity to obtain the data. If data from another company is required, the GVSDT believes that it should be available to the GO.		
SERC Dynamic Review Subcommittee (DRS)	Yes	The Transmission Planner is in the best position to determine the impact of the results on long term system reliability. Additionally, the Transmission Planner is often the entity that provides this data to other entities (via the MMWG process) for modeling and simulation purposes.
Response: The GVSDT thanks you for your comment.		
Bonneville Power Administration	Yes	BPA believes that the applicability from PRC-19-1, 4.1.2 “Transmission Owner that owns synchronous condenser(s)”, should also be applied to the applicability of MOD-025-2 with respect to Transmission Owners.
Response: The GVSDT thanks you for your comment. Although the applicability does not change, the wording has been modified to match PRC-019-1, 4.1.2 for consistency.		
Florida Municipal Power Agency	Yes	See comments to question 2
Response: The GVSDT thanks you for your comment. See response to question 2.		

Organization	Yes or No	Question 3 Comment
Consolidated Edison Co. of NY, Inc.	Yes	Please add the TP in the Functional Entities in section 4.1.
Response: The GVSDT thanks you for your comment. The GVSDT believes that since the Transmission Planner does not have any actions under the standard except receiving the data, addition of the Transmission Planner is not needed.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that the proper recipient is the Transmission Planner. There is no reliability reason that we are aware of to include Transmission Owner in the loop - as the previous version of MOD-025-2 called for.
Response: The GVSDT thanks you for your comment.		
City of Vero	Yes	See comments to question 2
Response: The GVSDT thanks you for your comment. See response to question 2.		
Tacoma Power	Yes	None
Southwest Power Pool Standards Development Team	Yes	
SERC Generation Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
Dominion- NERC Compliance Policy	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
SERC Planning Standards Subcommittee	Yes	
PPL	Yes	
ACES Power Standards Collaborators	Yes	
Puget Sound Energy	Yes	
Western Electricity Coordinating Council	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and	Yes	

Organization	Yes or No	Question 3 Comment
Gas		
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Wisconsin Electric Power Company	Yes	
Ameren	Yes	
Seattle City Light	Yes	
Cowlitz County PUD	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Seattle City Light	Yes	
Kansas City Power & Light	Yes	
Pepco Holdings Inc and Affiliates		No comment
Indiana Municipal Power Agency		no comment

4. **Do you have any other comment, not expressed in questions above, for the GV SDT regarding MOD-025-2?**

Summary Consideration: Stakeholders provided many suggestions for improvements to the language of the standard. Several stakeholders disagree with the use of "bulk power system" in the applicability. The GVSDT has revised this to use the term "Bulk Electric System" instead. Concerns were raised regarding the verification schedule for entities that own five or fewer units. The GVSDT removed Sections 5.1.1 and 5.2.1. Entities that own one unit will be required to verify their unit within two years. Entities that own two units will be required to verify one unit within two years and both units within three years. The GVSDT received some comments regarding the language in Attachment 1. As a result the GVSDT restructured item 2 of Attachment 1:

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

Some commenters had questions regarding Section 5.3 regarding wind farms. The GVSDT acknowledges that this statement was placed in the standard as an explanation and is not appropriate to be included as section 5.3 This information was expanded and included as a footnote rather than section 5.3:

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Organization	Yes or No	Question 4 Comment
Balancing Authority of Northern California	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of ‘bulk power system’ to ‘Bulk Electric System’ would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The SDT agrees and has made the change.		
Essential Power, LLC	Affirmative	1. There is a typo in R2- the requirement is for 'Reactive' Power verification, rather

Organization	Yes or No	Question 4 Comment
		than 'Real' Power verification.
Response: The GVSDT thanks you for your comment. The SDT agrees and has corrected the mistake.		
Pacific Gas and Electric Company	Affirmative	See comments from WECC
Response: The GVSDT thanks you for your comment. See response to WECC comments.		
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The SDT agrees and has made the change.		
Alliant Energy Corp. Services, Inc.	Negative	Alliant Energy believes the use of the term "bulk power system" in the context of this standard is incorrect and the term "Bulk Electric System" should be used instead.
Response: The GVSDT thanks you for your comment. The SDT agrees and has made the change.		
Beaches Energy Services	Negative	BPS vs. BES The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded is a prime example of this overreach). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards) To parallel the Section 215 definition of BPS at (a)(1) "The term `bulk-

Organization	Yes or No	Question 4 Comment
		power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..." We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". MOD-025 Applicable Facilities could be simply those that are not Black-Start., simplifying the language considerably
Response: The GVSDT thanks you for your comment. The SDT has changed references to the "bulk power system" to refer to the BES. Applicability to Black-Start units is no longer part of this standard as it is included in EOP-005-1.		
Brazos Electric Power Cooperative, Inc.	Negative	See ACES Power Marketing comments.
Response: The GVSDT thanks you for your comment. Please see the response to the ACES Power Marketing comments.		
Central Electric Power Cooperative	Negative	see Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see the response to the AECI comments.		
Clark Public Utilities	Negative	The effective date section of the standard provides a confusing implementation for a utility that has only one generator. Please address this issue. I suggest that you add the following to end of section 5.1.5, "This section applies to a Generator Owner and Transmission Owner having only one applicable facility."
Response: The GVSDT thanks you for your comment. The GVSDT has combined sections 5.1.1 and 5.1.2 so that entities with only one unit will have two years to complete a test.		

Organization	Yes or No	Question 4 Comment
Consolidated Edison Co. of New York	Negative	See Individual Company and NPCC Group comments
Response: The GVSDT thanks you for your comment. See response to Individual Company and NPCC Group comments.		
CPS Energy	Negative	1) The standard does not clearly define the term "applicable facility". Are variable generating units such as wind, solar, and hydro included or excluded as applicable facility. 2) Disagree with the new "A Introduction 5.3 Wind Farm Verification" statement. This is a technology specific exception without justification.
Response: The GVSDT thanks you for your comment. **1) Any Facility that meets the requirements of Section 4 of the standard are included as applicable facilities regardless of their type. In general, variable generation sources are included in the applicability of this standard, provided they meet the specifications in Section 4 of the standard.** **2) The GVSDT has removed section 5.3 and included it as a footnote to Section 5.1 and 5.2 which reads:** **"Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system."**		
Dairyland Power Coop.	Negative	Please see comments submitted by MRO NSRF.
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
Flathead Electric Cooperative	Negative	do not like the reference to bulk power system as opposed to bulk electric system, don't like the mixing of terms in the same standard/document
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the "bulk power system" to refer to the BES.		

Organization	Yes or No	Question 4 Comment
Florida Municipal Power Pool	Negative	See FMPA comments
Response: The GVSDT thanks you for your comment. Please see responses to FMPA comments.		
Great River Energy	Negative	Great River Energy agrees with the comments of the MRO NSRF and ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please see responses to MRO NSRF and ACES Power Marketing Comments.		
JEA	Negative	MOD025-2: 1) R2 should be changed from "Real Power" to "Reactive Power" since R1 deals with Real power while R2 deals with Reactive Power. 2) Staged testing should not be required but instead rely on providing a longer window for an excursion to occur. It makes little sense to say that four 15 MVA units at a facility (for a total of 60 MVA) will not need to be verified and yet a single 20 MVA unit will need to be verified. Suggest making a consistent rule of 75 MVA for both single and aggregate units which is alignment with current thinking on phase 2 of the definition of the BES. 3) The allowance for when a combined facility is less than 90% should be further refined to say that the net value must be greater than 75MVA to require testing - i.e. if a facility is only at 40% of 100MVA (only 4 of 10 - 10MVA units available) capacity then testing should not be required.
Response: The GVSDT thanks you for your comment. 1) The GVSDT agrees and has made this revision. 2) This comment relates to MOD-026 and MOD-027. MOD-025 requires a staged test at a steady-state output for the Real and Reactive Power output verifications. The GVSDT has incorporated NERC generator registry criteria as the applicability for this standard. 3) The 90% allowance only applies to the verification of the Reactive Power capability of the variable resources. This means that 90% of the units at a site have to be on-line and does not represent the actual power output of the site.		

Organization	Yes or No	Question 4 Comment
Lakeland Electric	Negative	See FMPA comments.
Response: The GVSDT thanks you for your comment. Please see response to FMPA comments.		
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Response: The GVSDT thanks you for your comment. Please see response to MRO NERC Standards Review Forum for LES' concerns.		
M & A Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
MidAmerican Energy Co.	Negative	The inclusion of "bulk power system" in these standards is inappropriate. The term bulk power system is broad, vague, and undefined. All entities, including regulators and regulated entities must clearly understand the scope of compliance. See the NSRF comments for further discussion.
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the "bulk power system" to refer to the BES.		
Midwest ISO, Inc.	Negative	See comments submitted by MRO NSRF.
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		

Organization	Yes or No	Question 4 Comment
Modesto Irrigation District	Negative	We strongly support generator testing and verification. However, the use of the undefined term "bulk power system" in the standard will lead to needless confusion. Also, we believe the intent of the coordination and testing standards is to recognize the importance to the Bulk Electric System (BES) of all interconnected generators with a capacity greater than 20 MVA. Hence, perhaps interconnected generators of this size should be included in the BES.
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the "bulk power system" to refer to the BES. Generators greater than 20 MVA are included in the applicability.		
Muscatine Power & Water	Negative	Please see the comments submitted by NSRS for Project 2007-09 Generator Verification.
Response: The GVSDT thanks you for your comment. Please see the response to NSRS comments.		
N.W. Electric Power Cooperative, Inc.	Negative	see Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
New Brunswick System Operator	Negative	See comments submitted by NPCC Reliability Standards committee.
Response: The GVSDT thanks you for your comment. Please see response to comments submitted by NPCC Reliability Standards Committee.		
New York Power Authority	Negative	See NPCC submitted comments
Response: The GVSDT thanks you for your comment. Please see response to NPCC submitted comments.		
North Carolina Electric	Negative	Please see the formal comments submitted by ACES Power Marketing.

Organization	Yes or No	Question 4 Comment
Membership Corp.		
Response: The GVSDT thanks you for your comment. Please see response to formal comments submitted by ACES Power Marketing.		
Northeast Missouri Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
Northern Indiana Public Service Co.	Negative	Confusion since the Bulk Power System (BPS) and Bulk Electric System (BES) are both mentioned within these standards; they are not the same
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the "bulk power system" to refer to the BES.		
Omaha Public Power District	Negative	OPPD supports MRO NSRF comments
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
Public Utility District No. 1 of Lewis County	Negative	Thank you for the opportunity to comment on the proposed standard MOD-025-2. Our utility owns and operated a smaller run-of-river hydroelectric plant with two 35MW units. The testing required in the proposed standard is onerous and quite expensive for small GO. To collect the required data would take an outside contractor to be hired. We do not understand why this data must be collected every five years for data that for a hydro does not change unless a generator winding fault or event occurs. Who uses this data? Suggest the following changes to Attachment 1 to the standard: Verification of data every 15 years or within 12 months if a change occurs. Only require MW & MVAR verification using operation data once every five years Paragraph 2.3 Conduct the maximum Real Power and over-excited Reactive Power required in 2.1 for a minimum of 5 minutes. Conducting these tests for one

Organization	Yes or No	Question 4 Comment
		continuous hour is like driving your car as fast as it can go in first gear - Nothing good comes out of it. I am concern about the overvoltage situation to our equipment. On line voltage runs high; being a smaller plant, we have ever little control over what the line voltage is. Running these tests for an hour would damage our equipment. Paragraph 2.6 If transformer loss data is not available then collect Generator Step-Up (GSU) transformer losses......... Transformer losses change very little through their life. I do not see the reasoning behind collecting this data every five years - seems like overkill to me. Paragraph 3.2 Do not understand the requirement about voltage schedule during a test. Running the reactive testing the voltage is going to run where the loading is going to take it. Please provide a further explanation MOD-025 Attachment 2 Our hydro plant does not track other plant loads - they are minor in nature and unlike thermo or nuclear plants are not a high percentage of generation. I would prefer that the standard requires for hydro plants that the nameplate real and reactive power limits be tested every five years. The other data is not necessary to obtain.
Response: The GVSDT thanks you for your comment. The GVSDT believes that due to the many factors that can affect Reactive Power capability, five years is the correct periodicity for re-verification. It is expected that the TP will use the data. Operation of units beyond their design capability is neither required nor expected. Attachment 1, Section 2.6 has been reworded for clarity. Transformer losses are meant to be measured or calculated so that new MW's and MVAR's can be determined. The voltage schedule for the test (and the voltage window) would be needed to be sure transmission voltage limits are not exceeded for the tests (coordination with the TO is expected). Your statement concerning a preference for testing hydro plants every five years does not seem to be consistent with an earlier statement suggesting verification every 15 years. The GVSDT, however, agrees that testing every five years is the correct verification frequency.		
Seattle City Light	Negative	Attachment 1 "Verification specifications for applicable Facilities:" section 2.3: It will be difficult to test at maximum power for one continuous hour at some plants due to operating restrictions regarding water flow or other factors.
Response: The GVSDT thanks you for your comment. In Attachment 1, Section 2.3, maximum power for variable energy units would be the highest power level (not emergency overload) that the unit can sustain for one hour. The GVSDT suggests		

Organization	Yes or No	Question 4 Comment
scheduling the tests requiring a one hour stabilization period when conditions are adequate. Alternately, you can test variable energy units at the level that can be sustained for one hour per Attachment 1, Section 2.1. Attachment 1, Section 2.1 also states that the output should remain as steady as possible during the verification period.		
Seminole Electric Cooperative, Inc.	Negative	a) 4.2: BPS is not a NERC defined Term in the NERC Glossary of Terms
Response: The GVSDT thanks you for your comment. The SDT has replaced references to "bulk power system" with the NERC defined term BES.		
SERC Reliability Corporation	Negative	Please see comments of SERC Dynamics Review Subcommittee regarding reactive capability planning.
Response: The GVSDT thanks you for your comment. Please see response to SERC Dynamics Review Subcommittee comments.		
Southwest Transmission Cooperative, Inc.	Negative	The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on subtransmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: "The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric

Organization	Yes or No	Question 4 Comment
		system." Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies that standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. We also find section 5.3 regarding wind farm verification confusing. What is its purpose?
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) Section 5.3 in the "Effective Date" was for clarification to let people know that a wind farm site, if it meets the applicable facility criteria, is a single site. This text has been moved to a footnote to the Applicability Section, 4.2.3.**		
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please see response to ACES Power Marketing comments.		
Tucson Electric Power Co.	Negative	Measure M1 references corrections for ambient conditions, while there is no reference to ambient conditions in Requirement R1. However, Requirement R1 requires verification in accordance with Attachment 1 and corrections for ambient conditions is identified in Attachment 1. This should be referenced or made clearer.
Response: The GVSDT thanks you for your comment. The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was		

Organization	Yes or No	Question 4 Comment
recorded/selected whichever is later."		
Xcel Energy, Inc.	Negative	Measure M1 creates a requirement to perform an activity that is not mentioned in the Requirements.
	Negative	Measure M1 creates a requirement "and a correction for ambient conditions, if requested, within 90 days to its Transmission Planner" not found within the Requirements section of the Standard.
Response: The GVSDT thanks you for your comment. The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."		
Central Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
Clark Public Utilities	Negative	The standard needs to recognize there are generator owners and transmission owners that have only a few applicable facilities and the percentage fulfillment requirement will be a cause of confusion. Please fix it now before the standard is approved.
Response: The GVSDT thanks you for your comment. The GVSDT has combined sections 5.1.1 and 5.1.2 so that entities with only one unit will have two years to complete a test.		
Luminant Generation Company LLC	Negative	Based on a comparison of R2 and corresponding VSL. It is unclear how the time frames are to be aligned. Comments on the standard provided in the on-line

Organization	Yes or No	Question 4 Comment
		comment form.
Response: The GVSDT thanks you for your comment. R2 requires that the verified data be submitted within 90 calendar days. The VSLs are based on a violation of that timing requirement.		
New York Power Authority	Negative	See NPCC Submitted Comments
Response: The GVSDT thanks you for your comment. Please see response to NPCC comments.		
Tucson Electric Power Co.	Negative	The Lower and Moderate VSLs for R1 both include missing 33 percent of the data in the condition identified after the first OR in the VSL. If an entity was missing exactly 33 percent of the required data, it would not be possible to identify an appropriate VSL. Suggest using "less than or equal to" and "more than" as more clear identifiers. Same for R3.
Response: The GVSDT thanks you for your comment. The VSL's have been modified for clarity as you suggest.		
Northeast Power Coordinating Council		1)This testing will be difficult to stage due to the four point reactive power testing. The power system may have to be reconfigured in many cases to allow for the changes in generator reactive power output, and the testing may not be able to be carried out when planned. System disturbances can occur that will disrupt the testing. 2)For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are "on-line". For reactive testing, this would be better stated as 90% of the plant's available capability considering that some wind turbines may be able to produce/absorb reactive power with no real power production. Does "on-line" just imply that the wind turbine breaker is closed and no requirement for real power production? 3)In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power

Organization	Yes or No	Question 4 Comment
		connected at the high-side of the generator step-up transformer (point D), and Aux or Station Service Real Power connected at other points of interconnection (point E). Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)? 4)The data requested in this Standard will verify a generator's capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies (and not include synchronous condensers). Therefore, the Purpose Statement be edited to read: "To assure accurate information on generator gross and net Real and Reactive Power capability Reactive Power capability is available for planning models used to assess BES reliability." 5) The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime, unless the generator has been rewound, cooling systems modified, installation of a new exciter, etc. 6) Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? A GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. 7) 2. Comments on Attachments 1 and 2: The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. 8)o Notes 1 - 4 at the end of Attachment 1 should be removed from the Standard

Organization	Yes or No	Question 4 Comment
		and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. 9)o Section 4.2.1 (and elsewhere): the term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability Sections is confusing.

Response: The GVSDT thanks you for your comment.

1) **The GVSDT acknowledges that other reactive resources may need coordination in order to complete a staged test. The standard encourages coordination to achieve better test results but does not require reconfiguration of the power system in order to facilitate a staged test.**
2) **The intent is to have 90% of the individual turbines or inverters on line with the breakers closed. There is no requirement for real power production from variable resources during reactive power testing.**
3) **Data is not required for points D and E but should be included if they exist. In many cases, these additional loads will not exist. They are listed to ensure that they are not included in calculating point F which is the net unit capability.**
4) **The GVSDT received overwhelming stakeholder support favoring the inclusion of synchronous condensers in the standard during the previous posting. The GVSDT believes that the purpose statement is adequate for the standard as written.**
5) **Periodic verification is necessary for discovering the equipment limitations that impact the unit MW or MVAR capabilities.**
6) **The GVSDT has removed 5.1.1 and 5.2.1 so that entities with only one unit will have two years to complete a test. Entities with two units would have three years and so on.**
7) **Data is required for all points if it is available. In accordance with the purpose statement of the standard, the data required is net real and reactive capability. Point A is the gross generator output. The verification of net output is required, so the other values are needed to derive the net. The ratings are just that, ratings not necessarily what can actually be output. As discussed in item 3, data is not required for points D and E but should be included if they exist. In many cases, these additional loads will not exist. They are listed to ensure that they are not included in calculating point F which is the net unit capability.**
8) **The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.**

Organization	Yes or No	Question 4 Comment
9) The GVSDT agrees and has made the revision from bulk power system to Bulk Electric System.		
SERC Generation Subcommittee		1) Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions (if requested), but this is not included in R1, Attachment 1 or Attachment 2. 2) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. 3) Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. 4) To accomplish the stated goal of Steady State Model Validation, there needs to be clarity in the definitions for model terms. We have developed a draft set of definitions that is available to the SDT. 5) Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which provided a process where an engineering review (with associated operating data) should be performed first with testing to be done on a limited basis, if needed, to capture data not covered by an operational review. The SDT could leverage this guide to better understand the approach, which was agreed to by the region's planning and generator operators. This approach should be adopted as an additional method to verification. 6) Testing may be desirable to identify issues, such as incorrect AVR limiter settings, but there are other methods that also would accomplish those goals. If the goal is operational testing to uncover these types of issues, that should be clarified in the

Organization	Yes or No	Question 4 Comment
		purpose of the standard as opposed to the stated goal of model validation. 7) Attachment 1, Verification specifications for applicable Facilities, Note 1: We recommend revising the last sentence to state, “The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit’s reactive capability for extreme system conditions. See Note 2.” 8) Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 9) The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. 10) Attachment 2, Summary of Verification - What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. o Applicability Section - change “bulk power system” to “BES”. 11) Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or “sister” units should be allowed. 12) Testing a unit to the limits of its protective function (such as overvoltage) creates

Organization	Yes or No	Question 4 Comment
		the possibility for an unplanned unit trip, particularly problematic on nuclear units.

Response: The GVSDT thanks you for your comment.

1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

2) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

3) The use of operational data is optional and not required. The intent of the suggested criteria was meant to be as flexible as possible while requiring a reasonable staged test to insure adequate effectiveness of the period/data chosen to use for operational tests.

4) The goal of MOD-025 is to verify real and reactive power output. The GVSDT believes that the data points shown in Attachment 2 are sufficiently defined to allow for accurate data to be reported.

5) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone.

6) The goal of MOD-025 is to verify real and reactive power output. The types of issues that you reference may impact the output.

7) Note 1 has been modified to incorporate the suggested wording.

8) Periodic verification is necessary to discovering the equipment limitations that impact the unit MW or MVAR capabilities.

9) The goal of MOD-025 is to verify real and reactive power output. The GVSDT believes that the data points shown in Attachment 2 are sufficiently defined to allow for accurate data to be reported. The Generator Owner provides the verification results to the Transmission Planner for inclusion in the development of their models.

10) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage

Organization	Yes or No	Question 4 Comment
appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2. 11) Credit may be taken for units that were tested under regional oversight if they fulfill the requirements of the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. 12) This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions.		
SERC Dynamic Review Subcommittee (DRS)	Yes	1) VAR-002-1.1b Requirement R1 states "The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator." However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. The DRS recommends that MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the DRS recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard.

Organization	Yes or No	Question 4 Comment
		2) On Attachment 2 Comment Section for Point A, add note that "individual unit values are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) 3) On Attachment 1, item 2.6, add sentence stating that "GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary." If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. 4) On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. 5) The DRS recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of "sister unit" concept. This will facilitate more consistent unit verifications. 6) The DRS agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. The DRS recommends that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar

Organization	Yes or No	Question 4 Comment
		changes which impact the reactive testing results. 7) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities.

Response: The GVSDT thanks you for your comment.

1) The GVSDT does not intend for a unit to change voltage regulator control modes in order to complete testing but simply makes it clear that testing is still to be done if the automatic voltage regulator is either not used or not available. It would be preferred that the test be rescheduled for a time when the automatic voltage regulator is operational if possible. Coordination of limiters with protection and generating unit capabilities is not the intent of this standard. Please reference PRC-019-1. MOD-025-2 also does not require operation outside the capabilities of the unit.

2) The GVSDT agrees that this change adds clarity, and will modify Attachment 2 as you suggest.

3) Your suggested revision has been adopted for clarity.

4) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.

5) Standards MOD-025-2 and PRC-019-1 are closely related and have been matched as closely as possible for consistency. These two standards, however, are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and therefore, would have a longer period between re-verifications.

6) After the first staged test, operational testing is allowed and further staged testing may not be required. Either operational or staged testing is intended to identify problems that cannot be identified by plant configuration change, major equipment changes, power system topology changes, or similar changes which impact the reactive testing results.

7) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

Organization	Yes or No	Question 4 Comment
Imperial Irrigation District (IID)		2.3 and 2.4 need clarification whether the real and reactive tests are run separately or concurrently and if that is 1 hour each or 1 hour total.
Response: The GVSDT thanks you for your comment. In Attachment 1, 2.3, the one hour stabilization period is required for MW testing and MVAR testing overexcited at full load. From Attachment 1, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard." If the tests are done at the same time a one hour stabilization period would be adequate (not one hour for each test). It is expected that the stabilization period done in 2.3 would most likely be a "worst case" scenario and therefore, would not need to be completed for the tests in Attachment 1, 2.4. The data for the tests in Attachment 1, 2.4 can therefore, be recorded as soon as the limit is reached.		
Santee Cooper		1) Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that's not included in R1, Attachment 1 or Attachment 2. 2) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. 3) Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. 4) Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which laid out a process where an engineering review and operating data should be performed 1st and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the regions planning and generator operators. This approach should be adopted as an

Organization	Yes or No	Question 4 Comment
		additional method to verification. 5) Attachment 1, Periodicity for conducting a new verification: 2) We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 6) The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. 7) Attachment 2, Summary of Verification - What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. 8) Applicability Section - change “bulk power system” to “BES”. 9) Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or “sister” units should be allowed. 10) Testing a unit to the limits of its’ protective function (such as overvoltage) creates the possibility for an unplanned unit trip, particularly problematic on nuclear units.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 4 Comment

1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

2) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

3) The use of operational data is optional and not required. The intent of the suggested criteria was meant to be as flexible as possible while requiring a reasonable staged test to insure adequate effectiveness of the period/data chosen to use for operational tests.

4) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone.

5) Your suggestion about the period of the re-verification cycle has merit and should be considered for a future revision to this standard if proven over time.

6) The goal of MOD-025 is to verify real and reactive power output. The GVSDT believes that the data points shown in Attachment 2 are sufficiently defined to allow for accurate data to be reported. The Generator Owner provides the verification results to the Transmission Planner for inclusion in the development of their models.

7) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.

8) The SDT has replaced references to "bulk power system" with the NERC defined term BES.

9) Credit may be taken for units that were tested under regional oversight if they fulfill the requirements of the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units.

Organization	Yes or No	Question 4 Comment
10) This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions.		
Dominion- NERC Compliance Policy		1)Dominion points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2. 2)Additionally, on Attachment 1 at 2.2, "Applicable Facilities" should be changed to "applicable Facilities" to be consistent with usage elsewhere in the standard. 3) VSL's for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33.* VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from "more than 12 calendar months but less than or equal to 13 calendar months" to "greater than 15 calendar months." 4) Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word "reactive" be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." 5) Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. 6) Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires..."

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. **1) We have revised the Applicability section by removing the phrase "bulk power system" and replacing it with the defined term "Bulk Electric System"** **2) We concur and have made the change.** **3) We have revised the VSLs to account for discrepancies in the percentages and months as you noted.** **4) Attachment 1, 2 has been modified for clarity and now reads in part: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **5) Attachment 1, 3.7 has been modified for clarity. It now reads: "The GSU Transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.** **6) Attachment 1, 3.4 has been modified for clarity as you suggested. It now reads in part: "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires….."**		
FirstEnergy		FirstEnergy has the following comments related to Attachments 1 and 2: 1. Att. 1 Sec. 2 - We suggest replacing the phrase "that demonstrated at least 50 percent of the capability of the associated D-curve" with "that demonstrated the maximum capability of the associated D-curve". 2. In addition, we suggest language as follows: "The reason(s) for any verified Reactive Power capabilities that, due to plant equipment, are more constraining than the appropriate generator Reactive Power capability curve (D-curve) shall be documented. (For example, exciter or generator field current limitations, generator terminal voltage, auxiliary or safety-related bus voltage limitations, volts per Hz alarms, excessive generator vibration, generator temperature limits, hydrogen

Organization	Yes or No	Question 4 Comment
		coolers restrictions, shorted rotor turns, safety, other protection, etc.) 3. Att. 1 Sec. 3.4 - Although we understand the drafting team does not want to be prescriptive and dictate an ambient temperature methodology, we believe the requirement is too broad and up for much interpretation across entities and regional auditors. There should be a more standardized method of determining the ambient adjustment for consistency, for example something similar to RFC standard MOD-024-RFC-01 Requirement R4.3.3. 4. We suggest adding the following or similar wording in the standard when a verification cannot be completed due to operational issues and include the allowance of engineering analysis to complete the verification: “1.2.3 If a verification test has been started and cannot be completed due to a transmission system limit or condition, this transmission system limit or condition shall be documented, and engineering analysis taking into account known limitations shall be used to determine the verified capabilities.”
Response: The GVSDT thanks you for your comment. **1) The phrase “that demonstrated at least 50 percent of the capability of the associated D-curve” was added recognizing that some units may always be limited by system conditions from reaching their D-curve. Operational testing would still be allowed on a re-test if it were within 90% of a previous test where a reasonable capability (50%) had been demonstrated. In our last posting we had stated exactly as you suggested but, in response to comments changed it to a more reasonable qualification.** **2) Reasons for not reaching the D-Curve are to be documented, see the “Remarks” section of Attachment 2.** **3) The GVSDT feels that the differences between units are too great to attempt an ambient temperature methodology to fit all and that it should be left up the owner to determine the best methodology for its units.** **4) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.**		
SERC Planning Standards		1) Change references to “bulk power system” in the Applicability section to “Bulk

Organization	Yes or No	Question 4 Comment
Subcommittee		Electric System." 2) VSL's for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33. 3) VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from "more than 12 calendar months but less than or equal to 13 calendar months" to "greater than 15 calendar months." 4) Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word "reactive" be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." 5) Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. 6) Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires..."

Response: The GVSDT thanks you for your comment.

1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.

2) and 3) We have revised the VSLs to account for discrepancies in the percentages and months as you noted.

4) Attachment 1, 2 has been modified for clarity and now reads in part: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a)

Organization	Yes or No	Question 4 Comment
that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." 5) Attachment 1, 3.7 has been modified for clarity. It now reads: "The GSU Transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer. 6) Attachment 1, 3.4 has been modified for clarity as you suggested. It now reads: "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires…"		
PPL		Comments: 1) A reference to power factor is needed in para. 2 of the Att.1 verification specification statement, "at least 50 percent of the capability shown on the associated D-curve." Is this criterion intended to apply at 1.0 PF? 2) Para. 2.1 of the verification specification in Att.1 is unclear in citing, "normal (not emergency) expected maximum Real Power." Normal operating level is typically not the maximum of which a unit is capable. Suggest this test-to generation be changed to, "normal full-load Real Power," defined as the output at which the unit usually runs for the ambient conditions existing at the time of the verification. 3) Add, "for the conditions existing at the time of the verification," at the end of the first sentence of para. 2.2 in the verification specification in Att.1. 4) Change "collect" to "correct for" in verification specification para. 2.6 in Att.1. 5) The statement, "The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions," in para. 3.4 of the verification specification of Att.1 is not clear. Possibly an "if" was intended before "the Generator Owner." A reference condition is also needed, or instructions for identifying the correct-to criteria, if the as-tested normal real power is to be adjusted for ambient conditions.

Organization	Yes or No	Question 4 Comment
		Such correction often does not apply for the purposes of this standard, however. A fossil unit with an emergency max capability of 750 MW on a 90 F day can achieve higher output at 60 F, for example, but the normal output may be 725 MW regardless of ambient conditions (see comments above). 6) Add, “Transformer Real and Reactive Power losses will also be estimates or calculations,” to para. 4.1 in the verification specification of Att.1, as well as the statement, “Only output data are required when using a computer program to calculate losses or loads.” 7) Note 2 the verification specification of Att.1 states, “While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification.” It is unclear who supposed to undertake such analyses and how they could be performed. Suggest this note be clarified or dropped. 8) The purpose of having a MOD-025 standard is undercut by the statement in Note 4 of the verification specification in Att.1 that “The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.” It is unclear why these tests should be performed if the results aren’t used? Could MOD-025-2 be withdrawn in light of FERC’s March 15, 2012 FFT Order to propose specific standards or requirements that should either be revised or removed due to having little effect on reliability or because of compliance burdens. 9) Add “Reactive Power” between “unit’s” and “capabilities” in Note 4 of the verification specification in Att.1. 10) It appears that the aux and net values requested in Att.2 are intended to be low-side readings, in which case they should be so-identified. 11) Delete from Att.2 the statement, “The recorded Mvar values were adjusted to rated generator voltage, where applicable.” Such adjustments may have unsuitably

Organization	Yes or No	Question 4 Comment
		high uncertainty.

Response: The GVSDT thanks you for your comment.

1) Attachment 1, 2 has been modified for clarity and now reads in part: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. For a Reactive Capability test, it must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive Power capability shown on the associated D-curve." It does not refer to a 1.0 PF test since this test is not required in this standard.

2) "Normal (not emergency) expected maximum Real Power" means the expected full load that can be counted on without configuring the unit in an unusual manner to gain additional MW's.

3) The GVSDT does not feel that the additional phrase adds clarity to Attachment 1, 2.2 as the generator owner selects the output at which the units are normally expected to operate.

4) Attachment 1, 2.6 has been modified for clarity and now reads: "Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU Transformer."

5) Attachment 1, 3.4 has been modified for clarity as you suggested. It now reads: "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires…". If a unit's capability does not change with ambient conditions, then that should be reported if requested by the Transmission Planner. The GVSDT has also added item 4.2 to Attachment 1: "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

6) The GVSDT concurs and has made the revisions suggested.

7) It is anticipated that Engineering Analysis would be performed by someone familiar with power system modeling. Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

8) Your comment applies to Note 1. The GVSDT has revised Note 1 to provide clarity on the intent of the statement. Note 1 now

Organization	Yes or No	Question 4 Comment
reads: "Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2." **9) Attachment 1, Note 4 has been modified for clarity. Note 4 now reads in part: "The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities."** **10) The auxiliary and station services values would be as measured at the 'high' side of those transformers. The net value is intended to be the net out of the generating unit or site as applicable. The GVSDT believes that the diagram is clear on these points.** **11) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.**		
ACES Power Standards Collaborators		1)We disagree with testing a unit with capability to operate in synchronous condenser mode in that mode. Most likely the unit would only operate in this mode in an emergency situation. Thus, it does not make sense to operate a unit in an emergency mode for a test. 2)We do not agree with adding a last verification data column in Attachment. This only causes confusion. Will it be clear to auditors that the last verification data column is to remain blank for the initial verification or will we end up with a similar situation to the Protection System Maintenance and Testing standard where auditors required evidence from before the enforcement date of standards? Ultimately, the NERC CEO had to overrule this situation. Furthermore, it creates additional work to transfer data from a previous verification test to the current test when the past sheet could simply be retained. Finally, it causes confusion with the data retention section because the data behind Attachment 2 must be retained. Is this intended to

Organization	Yes or No	Question 4 Comment
		be only the latest verification or does it include the last verification? 3)Item 2 of the verification specifications for applicable Facilities in Attachment 1 conflicts with Parts 1.2, 2.2, and 3.2 of the Requirements R1, R2 and R3. The attachment states that historical data going back two years can be used. However, the requirement parts state that the data must be submitted with 90 days to the Transmission Planner. That would appear to limit the historical data to 90 days. The attachment never makes it clear if you can switch between operational data and staged verification from one test to another. The confusion is caused by the separate listing of periodicities in items 1 and 2 under the "Periodicity for conducting a new verification" section. A close reading of the two items shows they are identical but listed separately to make the statement about listing the "earliest date of those dates" for the operational data. We suggest combining item 1 and 2 together will help eliminate this confusion. 4)We disagree with the need to conduct another staged test rather than using operational data as specified in Attachment I subsection 2 in the "Verification specifications for applicable Facilities:" section. If operational data can be used to satisfactorily verify the unit's real and reactive power output, it should always be allowed to avoid the need for a staged test.

Response: The GVSDT thanks you for your comment.

1) The standard applies to both stand alone synchronous condensers ad hydro units that can be used in condensing modes. The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator.

2) The intent of the drafting team in adding this information is to show compliance for the use of operational data. The drafting team cannot predict what auditors might do, but we will add a note that states this area would be blank for the first verification.

3) The GVSDT does not see a conflict because R1.2, R2.2 and R3.2 state that you have 90 calendar days from the date the data is selected, not the date the data is recorded. Requirement's R 1.2, R2.2 and R3.2 all state: "Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either

Organization	Yes or No	Question 4 Comment
the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data." **4) A staged test is always required for the first test as a part of this standard. The sentence "If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data" was added to disallow operational data being qualified based on a staged test that was not indicative of what can be expected from the unit due to unusual operating conditions at the time of the last staged test. Therefore, a successful staged test must be completed before operational data can be used on subsequent tests.**		
Puget Sound Energy		Very rarely will you get to the capability curve when testing real and reactive power. There is almost always a protective limit or you exceed 105% voltage. NERC does not specify what will prevent you from reaching maximum VAR output, so we assume that is up to the testing engineer.
Response: The GVSDT thanks you for your comment. The GVSDT agrees that it is up to the testing engineer to recognize when a limit has been reached. Coordinating with other nearby resources may allow you to reach the capability curve within the voltage limits of the unit. Attachment 2 requires documentation for the specific limit reached, see the section on "Remarks".		
Western Electricity Coordinating Council		1)Measure M1 specifically references corrections for ambient conditions as part of the evidence required, but Requirement R1 does not specifically call out corrections for ambient conditions. The only reference to corrections for ambient conditions is in Attachment 1. For consistency it seems the Requirement detail and the Measure detail should be the same. 2)The Lower and Moderate VSLs for R1 both include missing 33 percent of the data in the condition identified after the first OR in the VSL. If an entity was missing exactly 33 percent of the required data, it would not be possible to identify an appropriate VSL. WECC Staff recommends the use of the identifiers "less than or equal to" and "more than" to resolve the issue, and recommends that clarification be extended to the rest of this section of the VSLs for R1.The section of the VSLs for R3 that use percentages as the identifier should use "more than" and "less than or equal to" qualifiers.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. **1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** **2) The GVSDT has revised the VSLs to correct the problems that you noted.**		
Tennessee Valley Authority - GO/GOP		Testing a unit to the limits of its' protective function (such as overvoltage) creates the possibility for an unplanned unit trip. The SERC Regional Criteria for MOD-024 and MOD-025 allows an engineering assessment in conjunction with operational data review as a valid verification method. MOD-025-2 should include an engineering assessment as a valid method of verification.
Response: The GVSDT thanks you for your comment. This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions. Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.		
Arizona Public Service Company		Need for real power verification and reliability benefits are not clear. Similarly need for and reliability benefits of all the detailed calculations are not clear. The drafting team should poll the industry as to the reliability benefits and determine out who will use the information and what is the benefit of such detailed reporting.
Response: The GVSDT thanks you for your comment. Accurate, verified real and reactive Power output helps to ensure reliability in more accurate planning models as stated in the purpose statement of the standard: **"To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability."**		

Organization	Yes or No	Question 4 Comment
Southern Company		1) Applicability, Section 4: Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to focus on standard requirements that have significant impacts on system reliability, and including smaller units (without demonstrating their criticality to the system) seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where relability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. 2) Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 3) Attachment 1, Verification specifications for applicable Facilities, Item 2: Delete the requirements for mandatory "staged testing". Allow staged testing as an alternative. There is no industry consensus that staged testing is superior or achieves better reliability results for modeling purposes than the use of operational data coupled with a proper engineering study. A staged test performed every 5 years in our experience is not a substitute for proper planning, proper implementation of limiter and protection settings, equipment monitoring, unit data trending, and operational awareness and identification of plant equipment problems that could impact the MW or MVAR capabilities of a unit. Staged testing alone typically does not prove a unit's reactive capability, because the unit's true reactive limit cannot be reached due to transmission voltage and reliability constraints during the test period. We believe staged testing alone cannot accomplish the reliability

Organization	Yes or No	Question 4 Comment
		purpose of this standard. While staged testing can identify problems such as incorrect AVR limiter/protection settings or non-optimum transformer tap settings, these problems can be identified and corrected without staged on-line testing. 4) Attachment 1, Verification specifications for applicable Facilities, Item 3.4: This increases the complexity and reporting requirements for compliance. In practice, we believe the margins of error in transmission models do not require this level of detail and accuracy for periodic verification of unit MW capability. For the purposes of this standard, we believe recording of the MW for typical normal summer or winter conditions is sufficient. If a unit's MW capability is in question, TOP-002-2b R13 already has provisions for performing a more detailed verification, including ambient and water temperature conditions, at the request of the BA or TOP. 5) Attachment 1, Verification specifications for applicable Facilities, Note 1: Revise the last sentence to state, “The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit’s reactive capability for extreme system conditions. See Note 2.” 6) Please add page numbers to every page of the standard. 7) Attachment 2, Summary of Verification - What is the purpose for the fifth bullet? MVARs are a function of both the generator voltage and the system voltage. Thus, how to adjust the recorded Mvar values to rated generator voltage is not clear, is subject to dispute, and implies that engineering analysis is required to determine this result. 8) Attachment 2 Remarks - It is unlikely that the generator capability curve will be reached either during a lagging VAR test or during collection of operational data when a GSU tap has been set to support the normal system voltage ranges. The generator should be able to support the normal system voltage range without producing a large amount of Vars or amps so the Vars (or thermal capabilities) are held in reserve for extreme low voltage conditions. The transmission bus voltage will likely be the limiting factor during testing and normal operation. It is unlikely that

Organization	Yes or No	Question 4 Comment
		capability curve limit will be reached during either a leading VAR test or during collection of operating data. The limiting factor again is likely to be the transmission bus voltage. Likely unit operational limits which will prevent demonstration of the full range of the generator capability curve include the minimum excitation limit, the generator minimum voltage limit, or the station service minimum voltage limit. We recommend the Remarks statement be replaced with a list of possible limiting factors with checkboxes. If the transmission system voltage or a plant voltage limit is the limiting factor, the results of the test are inconclusive without performance of a supplemental engineering study. 9) The responsibility for requiring and coordinating any staged testing for the purposes of model validation already resides with the owners of the transmission models (i.e., the PC, TP, TOP and/or RC), not the GO or GOP. See TOP-002-2b R13. The TOP should initiate the request for the test and work with the GO/GOP to schedule the testing at a time when system conditions are optimal for testing that specific unit. The GO/GOP should only be responsible for supporting the TOP/RC during test scheduling, conducting the test, recording the necessary plant data, and reporting the test data and results, including any plant limitations encountered during the test. The GO/GOP can also perform any technical reviews and/or additional engineering analysis necessary to determine or confirm the expected MVAR limits to be used in the transmission models. This approach will better serve the reliability purpose of the standard. 10) Measure M1 doesn't match R1, or Attachment 1 or 2 regarding the submission of ambient condition correction information. (appears in M1, but not in the others) 11) An entity should be able to receive credit for real & reactive capability verification that has been done in the past 5-6 years which resulted from following existing regional requirements 1 12) For cases where operational data is used for verification, submittal of the results within 90 days of the date the data is recorded is inappropriate. Use of operational data involves the review and evaluation of unit data trends over an entire season as

Organization	Yes or No	Question 4 Comment
		a minimum. Two seasons are optimum based on our experience. R1.2 and R2.2 should be revised to state, “within 90 calendar days of completion of the verification.”

Response: The GVSDT thanks you for your comment.

1) The GVSDT matched the implementation times of MOD-025-2 and PRC-019-1 which are closely related standards. These standards are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and, therefore, would have a longer period between re-verifications.

2) Periodic verification is necessary to discovering the equipment limitations that impact the unit MW or MVAR capabilities.

3) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. The GVSDT does agree that staged testing is not a substitute for proper planning, proper implementation of limiter and protection settings, equipment monitoring, unit data trending and operational awareness and identification of plant equipment problems that could impact the MW or MVAR capabilities of a unit and these activities would be helpful in supplementing staged or operational testing.

4) The GVSDT does not feel it has been given the flexibility to eliminate corrections for ambient conditions due to the wording in FERC order 693, Paragraph 1310.

1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined.

Ambient temperature corrections are only required if it is requested by the Transmission Planner.

5) Note 1 has been modified to incorporate the suggested wording. Note 1 now reads “Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve).” However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap

Organization	Yes or No	Question 4 Comment
settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2. 6) Future versions of the standard will have page numbers on every page. 7) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2. 8) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. The GVSDT agrees that there will be cases were the verification will not reach the maximum or rated values. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. A staged test or operational data verification at least demonstrates that the equipment can successfully reach that operating point. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. The GVSDT does not feel a list is necessary nor will it add clarity and may even add further confusion to the document. The people performing the test are in the best position to determine and log the limiting condition. 9) MOD-025 deals with long-term planning models. The TOP-002-2b standard relates to operations planning and allows the BA or the TOP to request a test. It does not require a test on any periodic basis, but only upon request. 10) The GVSDT has removed "and a correction for ambient conditions, as requested" and added Section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." 11) Credit may be taken for units that were tested under regional oversight if they fulfill the requirements of the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units. 12) Requirement's R 1.2, R2.2 and R3.2 all clearly state: "Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data." This assumes that you		

Organization	Yes or No	Question 4 Comment
have already reviewed and evaluated the unit and data trends before you select the data. Attachment 1, 2 states in part "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability".		
PacifiCorp		Yes. See below: PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.1 of the "Applicability" section (as well as to sections 4.2.2 and 4.2.3). The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence would reads as follows: "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to Section 4.2.2 and 4.2.3.
Response: The GVSDT thanks you for your comment. The SDT has replaced references to "bulk power system" with the NERC defined term BES.		
Consolidated Edison Co. of NY, Inc.		Comments: 1. The data requested in this Standard will verify a generators capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies. Therefore, we recommend that the Purpose Statement be edited should read - o "To assure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BES reliability." 2) The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime,

Organization	Yes or No	Question 4 Comment
		unless the generator has been rewound, cooling systems modified, new exciter, etc. 3) Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. Is this the SDT's understanding?2. Comments on Attachments 1 and 2: 4) The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. 5) Notes 1 - 4 at the end of Attachment 1 should be removed from the Standard and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. 6) Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing.

Response: The GVSDT thanks you for your comment.

1) **The GVSDT received overwhelming stakeholder support favoring the inclusion of synchronous condensers in the standard during the previous posting. The GVSDT believes that the purpose statement is adequate for the standard as written.**
2) **Periodic verification is necessary for discovering the equipment limitations that impact the unit MW or MVAR capabilities.**
3) **The GVSDT has removed 5.1.1 and 5.2.1 so that entities with only one unit will have two years to complete a test. Entities with two units would have three years and so on.**
4) **Data is required for all points if it is available. In accordance with the purpose statement of the standard, the data required is net real and reactive capability. Point A is the gross generator output. The verification of net output is required, so the other**

Organization	Yes or No	Question 4 Comment
values are needed to derive the net. The ratings are just that, ratings not necessarily what can actually be output. As discussed in item 3, data is not required for points D and E but should be included if they exist. In many cases, these additional loads will not exist. They are listed to ensure that they are not included in calculating point F which is the net unit capability. 5) The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located. 6) The GVSDT agrees and has made the revision from bulk power system to Bulk Electric System.		
Luminant Energy Company LLC		Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour.2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as

Organization	Yes or No	Question 4 Comment
		soon as a limit is reached.2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section 3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2).On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope. 3)Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the simplified one-line diagram ..." Generator Owners can fill in the appropriate quantities at locations A-F. As an example, on some units values would be input for A, B, and F and NA entered for C, D, and E. 4)For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard.

Response: The GVSDT thanks you for your comment.

1) The GVSDT agrees and has revised the standard as proposed. One exception was regarding the sentence about retesting within six months. Another commenter noted an error within that sentence.

2) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.

3) The GVSDT worded this to allow GOs to use their own form as long as it provides the required information. We believe that this flexibility is appropriate, and Luminant's suggested wording seems to require the Attachment 2 form only. We, therefore, decline to adopt this change.

4) The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not

Organization	Yes or No	Question 4 Comment
requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.		
South Carolina Electric and Gas		1) Sections 4.2.1, 4.2.2, 4.2.3 uses the term "bulk power system." should this be changed to "Bulk Electric System." 2) Attachment I, "Verification specifications for applicable Facilities", #2. The third sentence should be revised to read "... at least 50 percent of the REACTIVE capability ..." 3) Also, in the VSL section: R1, Moderate VSL should read "34 to 66 percent of the data." 4) R1, R2, R3 Severe VSL should read "greater than 15 calendar months."
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The GVSDT agrees and has modified Attachment 1, Verification specifications for applicable Facilities for clarity. The sentence now reads in part "...at least 50 percent of the Reactive Power capability..."** **3) And 4) The VSLs were corrected to fix the discrepancies that you noted.**		
American Transmission Company, LLC		1. Please consider the following comments: Attachment 1, Periodicity for new verification Item 3 - Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or mutually agreed verification date." 2. Attachment 1, Verification Specifications Item 2.1 - There appears to be a typographical error near the end of Item 2.1, we believe that it should state, "Retest the facility within six months of being unable to reach the 90 percent threshold". 3. Attachment 1, Verification Specifications, Item 4.1, Note 1 - Consider deleting the

Organization	Yes or No	Question 4 Comment
		last sentence because it contradicts the purpose of the standard, contracts the sentiment of Note 2, and will likely to be untrue after verified values are entered into the Transmission Planner's database and are submitted according to MOD-010.
Response: The GVSDT thanks you for your comment. **1. The GVSDT believes that a 12 month verification period for new units is more than sufficient and does not believe that verifications beyond this timeline are necessary.** **2. The sentence was revised as follows: "Reschedule the test of the facility within six months of being able to reach the 90 percent threshold."** **3. The GVSDT concurs and has removed the last sentence.**		
Ingleside Cogeneration LP		1) Ingleside Cogeneration LP is concerned that there is no apparent provision in MOD-025-2 should a restriction in the extent of Reactive Power validation testing be placed upon the GO or TO by the Transmission Operator. In many cases, the TOP cannot allow the local system to operate beyond a certain Power Factor - especially when the system is supplying reactive power to the generator (leading). It may be the project team's intent that such a limitation is expected to be captured as a "Remark" in the reporting template (Attachment 2). However, we believe that the requirements must include allowable exceptions - as that is what Compliance Authorities will use to assess compliance. 2) Secondly, Measure 1 calls for a Generator Owner to provide correction factors for ambient conditions within 90 days of a request from the Transmission Planner. We agree with the reliability need, but believe there should be corresponding enforceable language in the requirement. 3)In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-025-2, which references generation connected to the "bulk power system"

Organization	Yes or No	Question 4 Comment
		rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities.
Response: The GVSDT thanks you for your comment. **1) The SDT believes that there are ample provisions in the standard to identify the fact that no limits are to be exceeded. For example attachment 1 - 2.1 refers to "normal (not emergency) expected maximum" Also, the standard requires the submission of the applicable voltage schedule, and lastly, the standard does not require the generating unit to achieve any particular output value, only that it be verified and reported.** **2) The GVSDT has removed "and a correction for ambient conditions, as requested" and added Section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** **3) The SDT has replaced references to "bulk power system" with the NERC defined term BES.**		
Independent Electricity System Operator		There is a typo on Row E in Attachment 2: The word "yransformers" should read "transformer".
Response: The GVSDT thanks you for your comment. The SDT has corrected the mistake.		
Public Service Enterprise Group (PSEG)		1) We have the following additional concerns: a. The entire section 4.2 has language that includes "directly connected to the bulk power system." The BES is a subset of the BPS per Order 743, and the GVSDT should consult with the SDT for Project 2010-17 - Definition of BES - to develop alternate language that instead refers to the BES. 2) We believe that the addition of section 5.3 (Wind Farm Verification) under the

Organization	Yes or No	Question 4 Comment
		"Effective Date" (section 5 in the standard) is both misplaced and confusing. A paragraph should be written in the "Verification specifications for applicable Facilities" section in Attachment 1 that follows paragraph 1 which would clarify for all generators how the percent verification of applicable Facilities in the "Effective Date" section should be calculated. The following is proposed:"1.1 The percent verification for applicable generating Facilities referenced in the "Effective Date" section of the this standard depends upon how the owner of generating units that are 20 MVA or less and that are part of a plant that is larger than 75 MVA in the aggregate choose to address verification. If the owner verifies the aggregate of all units that are less than 20 MVA as a group, then verification must include all of the aggregate units (i.e., a single applicable facility) taking into account the 90% threshold (which is considered "all") for wind turbines or photovoltaic inverters as provided in paragraph 2.1 below. If the owner verifies each unit that is less than 20 MVA on an individual unit basis, then the percent verification for that plant will be calculated on a unit basis. For example, suppose a plant has 5 units that are 20 MVA or less and 4 units that are greater than 20 MVA at a plant that in aggregate is greater than 75 MVA. If the owner chooses to verify each of the 20 MVA or less units individually, there are 9 applicable Facilities at the plant. If the owner chooses to verify the 5 units that are 20 MVA or less as a group, there are 5 applicable Facilities at the plant - one aggregate "Facility" comprised of 5 units that are 20 MVA plus or less plus 4 units that are greater than 20 MVA." 3) We are concerned with the requirements in Attachment 1 to perform tests, especially Reactive Power capability tests, with the automatic voltage regulator in service (paragraph 2 under the "Verification specifications for applicable Facilities" section) while maintaining the Transmission Operator's voltage schedule and Reactive Power output (see VAR-002-1.1b, R2). Unless R2 in VAR-002-1.1b is temporarily waived for staged tests, it may be impossible to meet paragraph 2.1 under the "Verification specifications for applicable Facilities" section in Attachment 1 since adjusting the Reactive Power output to verify leading and lagging power limits at maximum Real Power output may cause a violation of the cited VAR-002-

Organization	Yes or No	Question 4 Comment
		1.1b requirement. MOD-025-1 needs to address this issue. RFC's standard MOD-025-RFC-1 addresses the issue in its Attachment 1, paragraph 1.2, which states: "If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." 4) Paragraph 2 in Attachment 1's "Verification specifications for applicable Facilities" section has this statement: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve." What is meant by "50 percent of the capability shown on the associated D-curve"? Since the D-curve shows both Real and Reactive Power, would a previously staged test be acceptable if it demonstrated only 50 percent of the maximum Real Power capability per the generator's D-Curve? 5) In Paragraph 2.1 in Attachment 1's "Verification specifications for applicable Facilities" section, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. RFC's standard MOD-025-RFC-1 supports this position, since its Attachment 1 states: "Under-excited (leading) Reactive Power capability verification is not required of nuclear units." This sentence should be added to Paragraph 2.1 in Attachment 1. 6) In paragraph 2.2 in Attachment 1's "Verification specifications for applicable Facilities" section, the second sentence excludes nuclear units ("Units" is inappropriately capitalized in the standard this paragraph) from being required to

Organization	Yes or No	Question 4 Comment
		perform Reactive Power tests in paragraph 2.2. For clarity, we suggest that "nuclear" be included in the wind and photovoltaic exceptions in the first sentence, and that the second sentence be deleted. Paragraph 2.2 would thus read "Verify Reactive Power capability of all applicable Facilities, other than nuclear, wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate." 7) Note 1 in Attachment 1 states: "The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner's database; nor is it likely this value will agree with data required to be submitted by MOD-010." If MOD-025-2 data required by Transmission Planners, why wouldn't the data provided by Generator Owners per MOD-010 for Real and Reactive Power capability be the same data that is developed under MOD-025-1? The SAR for this project stated its purpose: "To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

Response: The GVSDT thanks you for your comment.

1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.

2) The GVSDT removed Section 5.3 and replaced it with a footnote on Section 4.3 " 1 Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system."

3) The GVSDT has added the suggested paragraph to Attachment 1.

4) These statements refer to the Reactive Power verifications. We have revised the language to clarify this:

"Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted

Organization	Yes or No	Question 4 Comment
(so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." 5) If a nuclear unit does not operate under-excited, then the Generator Owner should report that to the Transmission Planner. Several Generator Owners routinely test their nuclear units under-excited. This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions. 6) The GVSDT concurs with your comment and has revised the sentence per your suggestion. 7) The sentence was removed from Note 1 and it was revised as follows: "Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2."		
Xcel Energy		Measure M1 says that the Generator Owner must provide evidence that it has supplied the Transmission Planner with temperature corrected values upon request. Making temperature corrections is not stated in the Requirements or the Attachments. In essence, this is creating an additional requirement within the Measure which is not permissible. If the Drafting Team adds a requirement to perform temperature correction, then Xcel Energy strongly recommends that a Technical Reference be added to provide guidance doing the corrections so there is consistency in how the various Generator Owners perform the calculations.
Response: The GVSDT thanks you for your comment. The GVSDT has removed "and a correction for ambient conditions, as requested" and added Section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was		

Organization	Yes or No	Question 4 Comment
recorded/selected whichever is later." Variations in plant design would make a generic correction procedure extremely difficult. Therefore, the GVSDT feels that ambient conditions corrections should be done on an individual basis by the GO.		
Luminant Power		Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour.2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2).On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope.Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the

Organization	Yes or No	Question 4 Comment
		simplified one-line diagram ...” Generator Owners can fill in the appropriate quantities at locations A-F. As an example, on some units values would be input for A, B, and F and NA entered for C, D, and E.For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard.
Response: The GVSDT thanks you for your comment. **1) The GVSDT concurs with your suggested edits and have incorporated them into the standard. 2) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.**		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons: (1) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. (2) - Transformer Tap Settings - Under “Summary of Verification”, transformer tap settings should be replaced by transformer voltage ratio as tap settings on their own do not provide sufficient information. (3) - Effective Date 5.3 - 5.3 is too specific and should not be a separate sub-section in the Effective Date section. 5.3 should be removed and replaced with a general note explaining how verification percentages should be calculated for wind farms. Suggested wording - “Note - With respect to wind farm sites, the level of completion of verification shall be calculated on the basis of the number of sites, rather than the number of turbines at each site.” (4) - Temperature Range - Manitoba Hydro suggests that the GO should be required

Organization	Yes or No	Question 4 Comment
		to provide a unit's performance in a reasonable temperature range as specified by the Transmission Planner. (5) - Consistency in reference to capability curve - a unit's capability curve is referred to as a D-curve, D-Curve, thermal capability curve, Thermal Capability Curve, and MVAR capability curve in the standard. References to the curve should be consistent. We suggest the curve be referred to as 'Generator Capability Curve'. (6) - Notes 2 and 3 - Notes 2 and 3 should be removed from the standard as they do not seem to be required for compliance purposes and their inclusion creates a lack of clarity. (7) - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to all standards in this project.
Response: The GVSDT thanks you for your comment. **1) The GVSDT matched the implementation times of MOD-025-2 and PRC-019-1 which are closely related standards. These standards are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and, therefore, would have a longer period between re-verifications.** **2) The SDT modified the language to read "Transformer voltage ratio"** **3) The GVSDT has removed section 5.3 and incorporated it into a footnote: "[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system."** **4) Pertinent ambient condition data is to be recorded in Attachment 2, per Attachment 1, Section 3.4, to be used by the GO, if**		

Organization	Yes or No	Question 4 Comment
requested by the TP, to modify the Real Power test data to specified ambient conditions other than those at the time of the test. If the TP requests a correction to specific ambient conditions, it would be those conditions representing realistic, normal conditions for that area so that the most realistic Real Power capability can be used in planning studies. **5) The GVSDT has revised all instances to "thermal capability curve (D-curve)" for consistency.** **6) Notes 2 and 3 were added at the request of stakeholder comments to add clarifying information regarding the verification requirements. The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.** **7) The Evidence Retention language that you reference is NERC boilerplate language. However, the GVSDT has removed the phrase "and the previous set of evidence if updated since the last compliance audit" from the second paragraph of 1.2 of the Compliance section to correct a conflict between the second paragraph and the bulleted items. The GVSDT feels that the evidence retention period is specified to be since the last audit so the situation you describe could not occur for MOD-025-2.**		
Public Utility District No. 1 of Clark County		MOD-025 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60% and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-025. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Response: The GVSDT thanks you for your comment. The GVSDT has combined sections 5.1.1 and 5.1.2 so that entities with only one unit will have two years to complete a test.		
Los Angeles Department of Water and Power		Under MOD-025 Attachment 1, "Periodicity for conducting a new verification", Item 2, LADWP believes that the term "operation data" needs to be further clarified. Please provide the methodology and list of data types that qualify as meeting the requirement for verification using historical operational data.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. Operational data, as used in this standard, refers to all of the data that is included in Attachment 2 and recorded by systems such as Plant Information (PI) systems, etc. If all required data had been prerecorded at a time when the testing conditions were met and for the required period, that data may be used as a substitute for a staged test. Note that the operational data used for the Reactive Power verification must have demonstrated at least 90% of a previously staged test that reached at least 50% of the D-curve. If the previously staged test did not reach at least 50% of the D-curve then the next test must also be a staged test. The GVSDT cannot provide a methodology regarding operational data as this would be prescriptive and potentially limit what entities can do to provide data.		
Wisconsin Electric Power Company		1) In Requirement R2.1, the capability is to be verified at the "normal expected maximum Real Power" value. Since the verification cannot always be done in ideal conditions, there needs to be more flexibility in acceptable MW values to account for non-ideal conditions, such as wet coal, for example. A value of "greater than 90 percent of normal expected maximum Real Power" is recommended instead of "normal expected maximum Real Power". 2) Also in Requirement R2.1, the requirement for wind turbines is to have 90 percent of the turbines on-line for the verification. We support having a requirement of 50 percent of rated maximum Real Power, as specified in the ReliabilityFirst regional standard, MOD-025-RFC-01. Using a more attainable requirement for wind turbines will also eliminate the need for re-testing. The standard should have more flexibility for intermittent resources like wind. 3) In Requirement R2.2, the capability is to be verified at the "minimum Real Power output". It may be difficult to operate the unit in a reliable and stable manner exactly at the "minimum" MW value. We suggest allowing more flexibility when verifying at the minimum Real Power value. We propose to allow a range from the minimum Real Power value to the minimum value increased by 10 percent of the rated maximum Real Power. For example, if the maximum Real Power of a generator is 200 MW and the minimum Real Power is 50 MW, the verification for Reactive Power at minimum Real Power could be done anywhere between 50 MW and 70 MW Real Power. This or some other means of providing greater flexibility at

Organization	Yes or No	Question 4 Comment
		the lower end would especially be needed for coal units. 4) In Measure M1, there is a reference to providing values corrected for ambient conditions, if requested. There is no mention of this in the Requirements section. This wording should be deleted, or else any such requirement should be specifically included in the Requirements section. 5) In Attachment 1, 3.1, the values of Real and Reactive Power are to be recorded “at the end of the verification period.” It is suggested that the average (mean) values of these quantities over the verification period should be recorded, rather than simply the last value. 6) In Attachment 2, there is a requirement to provide net values at the high-voltage side of the GSU (Point F). This requirement should be deleted. The values for Gross, Auxiliary, and calculated low-side net are sufficient to document the verification. In addition, the required metering at this location may not be available. We have conducted field verifications for five years now, and the low-side values for MW and MVAR have been quite adequate.

Response: The GVSDT thanks you for your comment.

1) The GVSDT provided flexibility in Real Power and Reactive Power testing at full load with the following sentence in Attachment 1 section 2.1: “Verify Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities’ normal (not emergency) expected maximum Real Power at the time of the verifications.”

2) The standard does contain additional flexibility for intermittent resources such as wind to the extent needed. The GVSDT believes that the requirement to have 90% of the wind turbines on line at a particular site is more likely than having the wind site at 50% of its MW capacity. If you have evidence that indicates otherwise please provide that evidence to the GVSDT.

3) The GVSDT provided flexibility for testing at the minimum Real Power output in Attachment 1 section 2.2 which states: “Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.”

Organization	Yes or No	Question 4 Comment
4) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." **5) It is perceived by the GVSDT that recording data at the end of the test will better represent what the unit is capable of after it has stabilized. In most cases it is expected that data taken at the beginning of the test period and data taken at the end of the test period will be nearly identical. A requirement to average the data would unnecessarily complicate recording and analyzing the test results.** **6) The GVSDT feels that the value injected into the system, the high side net, is the value to be verified. If metering is unavailable, a calculated value may be used.**		
ReliabilityFirst		ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring generator verification of both Real and Reactive Power on a continent-wide level. This standard will also remove the Regional "fill in the blank" obligation to have Regional generator verification requirements. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. b. ReliabilityFirst requests clarification on why the term "Bulk Power System" is used rather than "Bulk Electric System." ReliabilityFirst interprets, that by using the term "Bulk Power System", units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. 2. Measure M1

Organization	Yes or No	Question 4 Comment
		a. The term "if requested" needs to be removed from the fourth line of Measure M1. The condition of "when requested" is not listed in Requirement R1. 3. VSL Requirement R1 a. The VSLs under the first "OR" statement should reference Attachment 1. This same language should be included in the VSLs for Requirements R2 and R3 as well. Here is an example of a "lower" VSL: "The Generator Owner verified the Real Power capability, per Attachment 1, and submitted the data but was missing 1 to 33 percent of the data. b. The Moderate VSL under the first "OR" statement, should be changed to state "...missing 34 to 66 percent of the data." As currently stated, missing 33% would fall under both the Lower and Moderate VSL category.
Response: The GVSDT thanks you for your comment. **1) The GVSDT has added specific information in the applicability section to account for synchronous condensers, which are not covered by the registry criteria.** **2) The GVSDT has removed "and a correction for ambient conditions, as requested" and added Section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** **3a) The proposed revision has been made.** **3b) The VSLs were revised to correct discrepancies with the percentages.**		
Ameren		(1)R1 and R2 require verification of the Real and Reactive Power capability of Applicable Facilities using Attachment 1. Attachment 1 ONLY allows verification by: (a) staged verification, or (b) verification using operational data. We suggest that the GVSDT add an additional option allowing engineering analysis verification.

Organization	Yes or No	Question 4 Comment
		(2) Replace the term “Bulk Power System” with “Bulk Electric System” in Applicability section, items 4.2.1, 4.2.2, and 4.2.3. The use of the term “bulk power system” throughout Section 4.2 Facilities should be replaced with the term “Bulk Electric System (BES)”. The use of the term bulk power system, which is not defined in the NERC Glossary, is problematic in determining which generating units and plants must comply with this new Standard. (3)In Note 1 of Attachment 1 to the draft MOD-025-2 standard, it is recognized that, at a given time, one or more generating units under test may not be able to reach full reactive capability as expected based on a review of the unit(s) thermal capability curve due to prevailing transmission system conditions. It is further recognized that the verified reactive power values obtained via testing will likely not agree with the reactive capability as used in model data submitted in compliance with Reliability Standard MOD-010. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed. As presently written, MOD-025 Attachment 1 allows only staged testing of the generating units or use of operational data. (4)The Attachment 1, Note 1 refers to the following. (a) The verification values produced by compliance with this new Standard. (b) The manufacturer’s D-curve values. (c) The Transmission Planner’s database values. (d) The MOD-010 values. Such multiple set of values appear to be in conflict with the purpose of the standard which is, “...ensure accurate information on generator gross and net Real and Reactive Power capability...is available for planning models used to assess Bulk Electric System (BES) reliability”? In this regard we fail to see a need for verification as suggested in this standard. We request the GVSDT to clarify if our interpretation is incorrect. (5)The middle paragraph on page 1 of Attachment 1 requires that any generator that can be operated in both generation mode and synchronous condenser mode must

Organization	Yes or No	Question 4 Comment
		be verified in EACH mode of operation - generation and synchronous condenser. We believe there should be exemptions for small hydro units which in frequently operate in the synchronous condenser mode. (6) Applicable size for the generating facilities in MOD-025-2, MOD-026-1, and MOD-027-1 should be consistent, which is a minimum size of 100 MVA. (7) Rather than a constant 5 year verification cycle, we suggest that the GVSDT consider a 10 year verification cycle with annual confirmation of the most recent verification. The first cycle could make use of the latest MOD-024-1 and MOD-025-1 values. (8) An option should be added for plants with more than one identical unit (sister units) allowing testing for one unit in place of all the identical units. Each cycle the GO should test a different sister unit until all have been tested. (9) Likewise, if MOD-010 data is still required, its requirements should be incorporated into this Standard in the next draft. (10) In the Implementation Plan, with the effective date of this standard, the previous version of related standards should be retired such as MOD-010. (11)Violation Severity Levels - R1 Moderate should be 34 to 66 percent. (12)In the R1 Severe Violation Severity Level, the last paragraph has same time frame shown as the R1 Lower VSL (more than 12 calendar months but less than or equal to 13 calendar months). (13)Violation Severity Levels - R2 Severe last paragraph has same time frame as R2 Lower - similar situation to comment above. (14)Violation Severity Levels - R3 Severe last paragraph has same time frame as R3 Lower - similar situation to comment above.

Response: The GVSDT thanks you for your comment.

1) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. Testing, either

Organization	Yes or No	Question 4 Comment
staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. 2) The SDT has replaced references to "bulk power system" with the NERC defined term BES. 3) Engineering analysis is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. 4) Your interpretation is incorrect. Note 1 is for clarification only, contains no requirements, and therefore, does not conflict with the purpose of the standard. The clarification provided by Note 1 is the result of requests for this clarification from previous comments. The Note is suggesting that the capabilities obtained from the verification may not match the D-Curve due to transmission limitations encountered during the test. Verification is needed to identify problems that cannot be discovered from engineering analysis alone such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc. 5) The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator. 6) MOD-026-1 and MOD-027-1 verify models. MOD-025-1 verifies Real and Reactive capabilities. Although loosely related the purpose of each of these standards is different. The potential for stated capability to be different from the capability that can be verified is large. With this in mind, the GVSDT has no basis to exclude generators that are included in the Registry Criteria and does not believe it is appropriate to do so. 7) The GVSDT believes that due to the many factors that can affect Reactive Power capability, five years is the correct periodicity for re-verification. The GVSDT also does not see how an annual confirmation would be less burdensome than a five year re-verification. 8) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. 9) Potential changes to MOD-010-0 should be discussed by that drafting team during the next review for that standard. 10) The possible retirement of MOD-010-0 should be discussed during its next review. 11, 12, 13, 14) We have revised the VSLs to account for discrepancies in the percentages and months as you noted.		
ISO New England Inc.		1) This testing will be difficult to stage due to the four point reactive power testing.

Organization	Yes or No	Question 4 Comment
		The power system will have to be reconfigured in many cases to allow for the changes in generator reactive output. For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are “on-line”. For reactive testing, would this be better stated as 90% of the plant’s capability available, considering some wind turbines maybe be able to produce/absorb reactive power with no real power production, or does on-line just imply that the turbine breaker is closed and no requirement for real power production? 2) In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power connected at the high-side of the generator step-up transformer (point D) and Aux or Station Service Real Power connected at other points of interconnection (point E) with no discussion? Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)?
Response: The GVSDT thanks you for your comment. **1) The GVSDT does not expect that reconfiguring of the power system would be required to perform the verification. It is recognized that it may be very infrequent that a wind plant is operating above 90% capacity. It is also recognized that many turbines are capable of producing or absorbing reactive power with little or no real power output. It is also recognized that it may be difficult to have all wind turbines available at one time, especially for larger wind plants. With this in mind, a demonstration with 90% of the wind turbines on-line should produce a reasonable approximation of the wind plants capabilities while making it easier to run a test from a logistics standpoint. It is the expectation of the GVSDT for a wind plant that at least 90% of the generator breakers are closed regardless of the MW output.** **2) Attachment 2 is meant to be generic, and applicable for several plant configurations. The desired values are ‘net to the BES’ which is point F for most configurations. Net values may be calculated values if metering at that point is not available.**		
Alberta Electric System Operator		1. In section 4.2, the AESO considers the existing applicability for reactive power verification to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger.

Organization	Yes or No	Question 4 Comment
		2. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect, or some qualifying language needs to be added.
Response: The GVSDT thanks you for your comment. The GVSDT is not able to justify including units outside the definition for the BES and Registry Criteria nor do we believe it is appropriate to do so. It is possible for WECC to create more stringent regional criteria to include the units you suggest if needed.		
TransAlta Centralia Generation LLC		The Transmission Operator (System Operator) should be included as an applicable functional entity since the Reactive Power verification test will to be coordinated by Transmission Operator (System Operator). There should be a requirement assigned to TOP for such coordination.
Response: The GVSDT thanks you for your comment. In accordance with the NERC reliability function model, Transmission Planners are required to report its planning results to Transmission Operators and because of this, the GVSDT does not believe the Transmission Operators need to be added to this standard.		
Seattle City Light		Attachment 1 "Verification specifications for applicable Facilities:" section 2.3: It will be difficult to test at maximum power for one continuous hour at some plants due to operating restrictions regarding water flow or other factors.
Response: The GVSDT thanks you for your comment. In Attachment 1 "Verification specifications for applicable Facilities:" Section 2.1 it states in part, "Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification." If the test can't be run at maximum power for one hour it is expected that the maximum power that can be sustained for one hour will be used for the verification.		
Cowlitz County PUD		1) Cowlitz understands the SDT must comply with FERC directive in Paragraph 1321. However, Cowlitz disagrees that requiring verification every five years will not be too

Organization	Yes or No	Question 4 Comment
		burdensome to the GO. Cowlitz is not confident that verification will be possible with operational data, and will be forced to verify via staged verification for at least two of the test points. We suggest that staged verification for four test points be required every 10 years with operational verification within 10% of at least one test point from the last staged verification being made no greater than 5 years after the staged verification. Should all four staged test points be confirmed via operational verification within 5 years of the last staged verification, then staged verification will reset to 10 years. If operational verification can't be provided within 5 years of the last staged verification, then one point must be verified via staged verification 5 years after the last full staged verification (all 4 points). 2) Cowlitz also disagrees with the generation applicability set at 20 MVA. This is arbitrary; FERC made no mandate in this regard and in fact shared a "concern with several commenters that such a requirement for all [Registered] generators may not be necessary." Cowlitz respectfully points out that it appears the SDT made no effort at all to determine true Reliability impact. Drafting Reliability requirements with no Reliability return must be avoided. SDT statements that simply state "the effort is not considered to be costly or burdensome" is not acceptable as it only offers an opinion without substantiating evidence.
Response: The GVSDT thanks you for your comment. **1) It is expected that some staged verifications will be required. The GVSDT believes that due to the many factors that can affect Reactive Power capability, five years is the correct periodicity for re-verification.** **2) The GVSDT has no evidence to exclude any registered generators from the requirements of MOD-025-2 nor do we believe that it is appropriate to do so. If Cowlitz County PUD has evidence it can share to suggest otherwise please provide that evidence.**		
American Electric Power		1) In section 4.2 for Facilities , the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC.

Organization	Yes or No	Question 4 Comment
		2) Item 5.3 appears to be one exclusive example. What if there are three wind farm sites? AEP agrees with the example given, but 5.3 should contain a high-level statement followed by the example provided. 3) We still oppose using language requiring that a standard be effective by "the first day of the first calendar quarter" x "calendar years following applicable regulatory approval". It is not clear exactly how this is to be interpreted. For example, if regulatory approval is granted on Feb 1 2013, is the standard effective on Jan 1 2014 or April 1 2014 if "x" is one year? For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year.
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The SDT has removed section 5.3 (Effective Date) and replaced it with a footnote as follows:** **[1]Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.** **3) The SDT has used language in the Effective Dates section that is consistent with many other standards and believes it to be clear.**		
Exelon		1) As stated in the previous comments from Exelon to Questions 5, 7, 12, 13 and 14 as documented in the Consideration of Comments on Generator Verification (MOD-025-2) - Project 2007-09 dated 2/22/12 (p81, p106, p150, p156 and p189), Nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. In response to Exelon's comments on Questions 5, 7, and 14 the

Organization	Yes or No	Question 4 Comment
		SDT states that [a nuclear plant] "should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities." In addition, the statement "Auxiliary bus voltage limits should be observed" was added to Note 1 of Attachment 1. As further stated in Summary Consideration for Question 5, the SDT has added Note 4 to Attachment 1 that states that "The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability, or the minimum lagging capability at which it can operate."Exelon requests that this note be further clarified as follows:"The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability or the unit is restricted due to other regulatory, unit stability or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate." In response to Questions 12 and 13 to Exelon's comments, the SDT further states that "Nuclear units are not required to perform Reactive Power verification at minimum Real Power output" as currently stated in Attachment 1 Verification Specification 2.2. Exelon requests this be revised to clearly state that nuclear units should also not be required to perform under-excited (leading) reactive capability verification. Attachment 1 Verification Specification 2.2 should be revised as follows:2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output and are not required to perform under-excited (leading) Reactive Power verification. 2) With respect to all of the Notes provided on the current draft MOD-025 Attachment 1, Exelon requests that the Notes be tied to the verification specification that they are referring to. 3) Historically Exelon has noted that its larger generating units have not been able to attain all of the data necessary for an over-excited full load and minimum load reactive power verification on the same test day due to grid constraints. Please

Organization	Yes or No	Question 4 Comment
		clarify that it is acceptable to perform segments of the reactive power verification on different test days as long as each portion of the test is performed for the required duration. 4) Please explain what is meant by the statement "[T]he recorded Mvar values were adjusted to rated generator voltage, where applicable" in the Summary of Verification section of Attachment 2. 5) The last Section of MOD-025-2 Attachment 2 requires certain Verification Data to be provided by unit or Facility, as appropriate. Exelon suggests that both the "rated" and "as tested" generator hydrogen pressure values be recorded as a comparison. Suggest the following be added to the Summary of Verification in Attachment 2: o Generator hydrogen pressure (if applicable)Rated pressure: _____________As tested pressure: _____________ 6) In the Consideration of Comments on Generator Verification (MOD-025-2) - Project 2007-09 dated 2/22/12 (p12), the SDT responded to the industry that it anticipated that Regional Standards would be retired once MOD-025-2 is approved. In addition, the SDT added language specifically to the Implementation plan to address the intent of ReliabilityFirst (RFC) to perform a review of both MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC BOT approval of NERC MOD-025-2. RFC has recently announced that they are "suspending Regional Standards efforts." On the NERC website MOD-024-RFC-01 is RFC Board Approved and MOD-025-RFC-01 is NERC BOT Adopted. Exelon is unsure of the status of both MOD-024-RFC-01 and MOD-025-RFC-01. With respect to the wording added to the Implementation Plan for MOD-025-2; what is the status of the intended review by RFC of both Regional Standards upon NERC BOT approval of the associated NERC MOD-025-2 Standard?
Response: The GVSDT thanks you for your comment. **1) The GVSDT disagrees with not requiring a verification to define the unit's reactive capability. A full load lagging capability verification does not adequately define the unit's reactive capability. The GVSDT believes that a nuclear unit can be tested at full load in both lagging and leading capability within the safe operating limits of the unit and reaffirms that challenging the plant's**		

Organization	Yes or No	Question 4 Comment
safety systems is not required by this standard. The GVSDT is aware of nuclear units that have been safely tested to their leading power factor limits. This standard does not restrict an entity from declaring that a unit has no leading power factor capability if it has determined that leading power factor capability does not exist. The limitations can be described in the "Remarks" section of Attachment 2. **2) The Notes were added at the request of stakeholder comments to add clarifying information regarding the verification requirements. The GVSDT received conflicting comments concerning the Notes in Attachment 1 and where to place them. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.** **3) The GVSDT confirms that testing different points at different times is allowed and may be necessary as you suggest. Attachment 1, Periodicity section, has been revised for clarification.** **4) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.** **5) The SDT has revised the item to "Generator hydrogen pressure at time of test (if applicable) ______________". The GVSDT believes that this clarifies the data required and eliminates any possible confusion.** **6) It is the understanding of the GVSDT that RFC has approved the standards but has not filed them for regulatory approval pending approval of MOD-025-2. RFC will re-evaluate the two standards upon approval of MOD-025-2 and will make revisions and / or retirements as necessary.**		
Texas Reliability Entity		1)Facilities--Avoid use of "bulk power system." There is inconsistency between the Standards in this Project with regard to applicable Facilities. Suggest using BES definitions or Transmission Planner requirements (if TP requirements are inclusive of BES as a minimum). 2)Effective date 5.3: "Wind site" is not defined.

Organization	Yes or No	Question 4 Comment
		3)Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning models for specific periods. 4)It is unclear whether this Standard requires Gross or Net (or both) capabilities to be verified. The Attachments seem to allow for either, to some degree, but is not definitive. It should be clearly stated which is expected.The following comments refer to the Attachment 1: 5)In Attachment 1 the term "commercial operation date" is used. The phrase should be more along the lines of "initial synchronization to grid," as a commercial operation date may be an extended time from initial synchronization. In general, there would be manufacturer's data that may be used in models but it is critical to understand the capabilities early on. 6)How does one determine what changes are "expected" to make a 10 percent change in last reported capability? We suggest deleting "is expected to." 7)Attachment 1 item 2.1: We recommend changing the real/reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. Also, we recommend changing the first sentence as follows: "Verify gross and net Real Power capability, gross and net Reactive Power capability over-excited (lagging) and gross and net Reactive Power capability under-excited (leading)......". 8)Attachment 1 item 2.2 appears to allow wind and photovoltaic "applicable facilities" to not have to verify Reactive Power capability at a minimum Real Power output. Is that the expectation of the SDT? At least in 2.1 there were statements regarding what was expected of wind and photovoltaic Facilities for Real and Reactive Power at expected maximum Real Power "at time of the verifications." 9)Attachment 1 item 2.3: What is the basis for "one continuous hour?" What is the expected value(s) to be provided for the continuous hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and

Organization	Yes or No	Question 4 Comment
		wind turbines may not allow for a full hour. Additionally, system conditions must be taken into effect for tests (disturbances that do not necessarily put the system into an emergency situation but may impact capability). Current ERCOT regional criteria for the Reactive Power leading and lagging tests is 15-minutes. 10)Attachment 1 item 2.4: Is this meant to be an instantaneous value to be collected? Or do the units have to maintain the verified value for an hour? Is the intent of 2.4 captured in 3.1 (as 3.1 appears to be a value recorded at the end of the verification period)? 11)Attachment 1 Section 3 does not include all the measurements shown in Attachment 2. While Form 2 may be changed (hopefully under the direction/guidance of the TP), section 3 should at least capture what measurements are portrayed in the Attachment 2 form as it exists. 12)Attachment 1 item 3.2: This is unclear regarding seasonal expectations and how to capture those expectations in a verification activity. As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. 13)Attachment 1 items 3.3 and 3.6: “Interconnection” should not be capitalized. 14)Attachment 1 item 3.4: Should include “Others as applicable” to match Verification Data form. 15)Attachment 1 item 3.8 is not captured on Verification Data form. 16)Change MVAR to Mvar in the “Notes” section of Attachment 1.Attachment 2 17)The first part of Attachment 2 assumes a single point of interconnection (Point F). Should there just be a requirement to supply a detailed one-line with measurement points noted and remove the sample one-lines?

Organization	Yes or No	Question 4 Comment
		18)In the Verification Data form, the use of the phrase “connected at the same bus” may have different interpretations than expected. Suggest removing the phrase or at a minimum changing the phrase to “measured at sites connected to the low side voltage level(s) of the GSU”. It should be noted that Auxiliary and tertiary loads (in terms of Real and Reactive Power) are not necessarily “connected at the same bus.” 19)Why is “N/A” in a few locations on the Verification Data form? 20)Please change the Verification Data form to use the same terms in the definitions of Net Reactive and Net Real Power (form calls for Gross Reactive Power Generating Capability” but definitions of Net do not use same term). VSLs 21)VSLs for R1- Suggest matching the language of the requirement with regard to “date the data is recorded for a staged test” or to the changes suggested for R1 (“date of a” staged test). 22)VSLs for R1- Suggest matching the language of the requirement with regard to “the date of the historical operating data that was selected.” The Requirement states “the date the data is selected for verification using historical operational data” which may be different than the date of the historical operating data (that was selected). 23)VSLs for R1- The second “OR” statement is not auditable if the Verification Data form is allowed to be changed. If the form had a minimum data requirement that had to be provided, a VSL could be created. As written, the statement “The Generator Owner verified the Real Power capability and submitted the data but was missing 1 to 33 percent of the data” and variations thereof cannot be audited. 24)VSLs for R1- Suggest adding “Real Power” in the third and fourth “Or” statements as R1 only refers to Real Power-“The Generator Owner performed the Real Power verification...” 25)Severe VSL for R1- The last “OR” statement needs corrected as it is the same

Organization	Yes or No	Question 4 Comment
		language for the Lower VSL. Suggest changing to the following: "The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months. " 26)R2 VSLs have the same comments as R1 VSL with the exception of adding "Reactive Power" instead of "Real Power" in the suggested locations. 27)R3 VSLs have the same comments as R1 VSL with the exception of adding "Reactive Power" instead of "Real Power" in the suggested locations. Additionally, there are multiple references to "Generator Owner" that should be replaced with "Transmission Owner."

Response: The GVSDT thanks you for your comment.

1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.

2) The SDT has removed section 5.3 (Effective Date) and replaced it with a footnote as follows:

[1]Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

3) In Attachment 1, Section 3.4, the Generator Owner is required to record the data needed to make corrections for different ambient conditions. If a Transmission Planner requests corrected test results for specific ambient conditions the recorded data can be used to provide that information.

4) The table in Attachment 2 requests net capabilities. This is the desired verification. Other values are collected to support obtaining the net values.

5) Twelve months from "commercial operation date" is deemed to be sufficient by the GVSDT. Using the first date the unit synchronized to the grid may be problematic as there could be an extended period of time when other issues could prevent verification testing.

6) The GVSDT concurs and has made the revision.

7) The GVSDT at one point considered allowing Reactive Power full load testing to be at least 95% of rated full load MW's but with

Organization	Yes or No	Question 4 Comment
the merger of MOD-024-2 into MOD-025-2 it was determined that allowing a Real Power test at 95% of full load MW's was not justified and would only add confusion. In addition the wider spread between full load and minimum load test points for Reactive Power capability provides a better approximation of the capability curve. 8) It is the intent of the GVSDT to not require Reactive Power testing of wind and photovoltaic plants at more than one Real Power output. The characteristics of the plants, and difficulty reaching a maximum or minimum load diminishes any benefits of the additional test. 9) One continuous hour was established as a minimum time for verification to verify that there are no equipment related issues with operating at the verification levels. 10) Section 2 of Attachment 1 has been revised in response to several commenters. The Reactive capability values now specified to be recorded are instantaneous values as indicated in revised section 2.2. 11) Attachment 2 was developed to account for different configurations and not all data will need to be recorded for every configuration or verification. The intent is to be able to develop a net Real and Reactive Power output for applicable Facilities. 12) In Attachment 1, Section 3.4, the Generator Owner is required to record the data needed to make corrections for different ambient conditions. If a Transmission Planner requests corrected test results for specific ambient conditions the recorded data can be used to provide that information. 13) The SDT agrees and has made the changes you suggest. 14) Attachment 1 Section 3.4 includes the phrase "such as" before the list indicating it is not a complete list. We also added a bullet "Other data as applicable" to Section 3.4. With this, the SDT believes it is compatible with Attachment 2. 15) The check boxes in Attachment 2 include Operational Data and Staged Test Data check boxes. These represent what is listed in Attachment 1 Section 3.8 16) The SDT agrees and has made the changes you suggest. 17) The diagram is meant to be generic, and represent several possible topologies. Generator Owners may use their own diagram if they wish as long as it supplies the required information. Parts of the diagram that do not apply to your particular site are to be left blank or marked N/A. 18) The commenter has not provided a description what alternative interpretation of "connected at the same bus' they believe will occur. This makes it difficult to respond to the comment. The GVSDT believe that language is clear.		

Organization	Yes or No	Question 4 Comment
19) We have removed these instances. **20) We have removed the word "generating" from the term "Gross Reactive Power Generating Capability (*Mvar)" and Gross Real Power Generating Capability (*Mvar).** **21) The SDT agrees and has made the changes you suggest to the VSLs.** **22) The SDT agrees and has made the changes you suggest to the VSLs.** **23) The note to Attachment 2 allows changes to the form but requires that "all required information is reported". Since this is included the VSL should be valid.** **24) The SDT agrees and has made the changes you suggest to the VSLs.** **25) We have revised the VSLs to account for discrepancies in the months as you noted.** **26) The SDT agrees and has made the changes you suggest to the VSLs.** **27) The SDT agrees and has made the changes you suggest to the VSLs.**		
Entergy Services, Inc	Yes	1) VAR-002-1.1b Requirement R1 states "The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator." However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. Entergy recommends that MOD-025-2 Attachment 1 verification

Organization	Yes or No	Question 4 Comment
		specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the Entergy recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard. 2) On Attachment 2 Comment Section for Point A, add note that “individual unit values are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) 3) On Attachment 1, item 2.6, add sentence stating that “GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.” If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. 4) On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. 5) Entergy recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of “sister unit” concept. This will facilitate more consistent unit verifications. 6) Entergy agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is

Organization	Yes or No	Question 4 Comment
		necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. Recommend that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar changes which impact the reactive testing results. 7) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities.

Response: The GVSDT thanks you for your comment.

1) The GVSDT does not intend for a unit to change voltage regulator control modes in order to complete testing but simply makes it clear that testing is still to be done if the automatic voltage regulator is either not used or not available. It would be preferred that the test be rescheduled for a time when the automatic voltage regulator is operational if possible. Coordination of limiters with protection and generating unit capabilities is not the intent of this standard. Please reference PRC-019-1. MOD-025-2 also does not require operation outside the capabilities of the unit. The Notes were added at the request of stakeholder comments to add clarifying information regarding the verification requirements. The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Note 3 has been modified to eliminate the caution about not exceeding machine limits if in manual voltage control.

2) The GVSDT agrees and has made this change.

3) Attachment 1, 2.6 has been modified for clarity.

4) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.

4) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.

Organization	Yes or No	Question 4 Comment
5) Standards MOD-025-2 and PRC-019-1 are closely related and have been matched as closely as possible for consistency. These two standards, however, are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and, therefore, would have a longer period between re-verifications. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. **6) After the first staged test operational testing is allowed and further staged testing may not be required. Either operational or staged testing is intended to identify problems that cannot be identified by plant configuration change, major equipment changes, power system topology changes, or similar changes which impact the reactive testing results.** **7) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.**		
Duke Energy		1) R1 requires the Generator Owner to verify Real Power capability per Attachment 1, and submit the data per Attachment 2. While Section 3.4 of Attachment 1 requires collection of ambient condition measurements needed to perform corrections to Real Power for different ambient conditions, MOD-025-2 doesn't require that the Generator Owner make corrections for specific conditions (such as summer peak day, etc.), and also doesn't provide for the Transmission Planner to request verification for any conditions other than whatever conditions existed during the verification required by this standard. Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that's not included in R1, Attachment 1 or Attachment 2. MOD-025-2 should either specify the conditions for which the Generator Owner must make corrections to real power, or should require the GO to make corrections to any conditions when specified/requested by the TP/TOP. A requirement should be added for the Generator Owner to provide the Transmission Planner with verification of Real Power capability for different ambient conditions within 90 days of a request by the Transmission Planner.

Organization	Yes or No	Question 4 Comment
		2) R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which engineering analysis is required for model verification. SERC developed a generator model validation guide in ~ 2004, which laid out a process where an engineering review and operating data should be performed first and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the region's planning and generator operators. 3) Attachment 2, Summary of Verification - Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) o Applicability Section - change "bulk power system" to "BES".

Response: The GVSDT thanks you for your comment.

1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

2) Engineering analysis in encouraged though not required by this standard. Engineering analysis may reveal additional MVAR capability that is not able to be demonstrated during a verification test and can be presented to the TP for consideration. It is

Organization	Yes or No	Question 4 Comment
usually most desirable to perform overexcited tests when the system voltage is low and underexcited tests when the system voltage is high. System conditions may not play as big of a role if there are other units or reactive resources nearby to counter the Reactive Power generated or absorbed for the test. The operational data that would be used to assist in the engineering analysis is the same data required for a staged test (see Attachment 1, 3.1 through 3.8). Again, the engineering review that you suggest is encouraged though not required because many utilities may not have the resources to perform such analysis. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. **3) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.**		
American Wind Energy Association		Overall, the draft standard is well-drafted and well help to improve reliability, and I would like to see it pass this round of balloting. If there is another round of revisions to this draft standard, it may make sense to look at this recently added section to make sure that it is a workable requirement for all wind projects: "If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold." For some wind plants, it may be difficult to schedule a test or retest at a time when 90% of the wind turbines are producing. Some wind plants may have significant periods of time when they have fewer than 90% of their wind turbines producing for reasons beyond their control (wind resource availability), and it is typically not possible to predict when those time periods will occur more than a day or two in advance. Repeated attempts at retests until one coincides with a period of sufficient wind resources may not be the most efficient process for testing a plant. Obtaining additional input from wind plant owners would help to clarify this issue, and if that input indicates a concern, the drafting team may want to change the 90% threshold or provide additional flexibility in the testing process to ensure that this standard will be workable for all wind

Organization	Yes or No	Question 4 Comment
		projects.
Response: The GVSDT thanks you for your comment. It is also recognized that it may be difficult to have all wind turbines available at one time, especially for larger wind plants. With this in mind, a demonstration with 90% of the wind turbines on-line should produce a reasonable approximation of the wind plants capabilities while making it easier to run a test from a logistics standpoint. It is the expectation of the GVSDT for a wind plant that at least 90% of the generator breakers are closed regardless of the MW output.		
Indiana Municipal Power Agency		1)Under 4.2 Facilities, IMPA recommends replacing bulk power system with Bulk Electric System which is used in NERC Standards. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)M1 states that the Generator Owner will have evidence that it submitted a correction for ambient conditions. In requirement 1, it does not state that the Generator Owner shall submit a correction for ambient conditions. Either requirement 1 or Measure 1 needs to be corrected to the intent of the SDT. 3)While realizing that the field or armature may be the limiting component in certain segments of the a generator's capability curve, IMPA does not see any value in making a generating unit verify its under-excited Reactive Power capability and over-excited Reactive Power capability at minimum Real Power. Operation at these points at minimum Real Power will seldom if ever happen. IMPA recommends deleting the requirements for reactive capability at minimum Real Power. 4)When at maximum Real Power, it is not clear what over-excited Reactive Power level a generating unit is to maintain for an hour when at maximum Real Power to constitute an acceptable test. IMPA believes in many instances units will reach a limit, such as volts per hertz, and will not be able to reach the over-excited reactive power curve. A Reactive Power test should be acceptable as long as it stays at a documented, reached limit for an hour and should not be required to retest within 6 months. IMPA recommends that the SDT makes its intent clear on what constitutes an acceptable test when at maximum Real Power and over-excited Reactive Power

Organization	Yes or No	Question 4 Comment
		capability.
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** **3) FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.** **4) The level of Reactive Power is unimportant for a Real Power test. If doing both the Real Power and a Reactive Power test at the same time, the unit should be operated at the maximum attainable Reactive Power (lagging), at normal (not emergency) expected maximum Real Power, for one hour to be considered a valid Reactive Power test. The limiting factor should be recorded after one hour per Attachment 2. The stabilization period of one hour applies to both the Real Power test and the Reactive Power (lagging) tests only. If doing the two tests at the same time the stabilization periods run concurrently.**		
Kansas City Power & Light		Should replace "bulk power system" with "Bulk Electric System". Use of "bulk power system" is ambiguous where as "Bulk Electric System" is fully defined.
Response: The GVSDT thanks you for your comment. The SDT has replaced references to "bulk power system" with the NERC defined term BES.		
MRO NSRF		1) In the applicability section reference is made to bulk power system which is an defined term. To avoid confusion as to which generating units are required to comply with this standard, use of the defined term, Bulk Electric System, is recommended. The purpose of MOD-025-2 refers to the "BES reliability" but Facilities listed within 4.2, speak of generation units connected to the BPS. This

Organization	Yes or No	Question 4 Comment
		difference of term does not provide consistency within this proposed Standard. The BES Drafting Team has established a set of "inclusions" that will "pull in" generation units that may not be connected to the BES. 2) Attachment 1, Periodicity for new verification Item 3 – Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or mutually agreed verification date between the Generator Owner and Transmission Planner" 3) Attachment 1, Verification Specifications, Item 4.1, Note 1 – Consider deleting the last sentence because it contradicts the purpose of the standard, contracts the sentiment of Note 2, and will likely to be untrue after verified values are entered into the Transmission Planner's database and are submitted according to MOD-010. Please clarify the purpose of this statement.
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The GVSDT believes that a 12 month verification period for new units is more than sufficient and does not believe that verifications beyond this timeline are necessary.** **3) The GVSDT concurs and has removed the last sentence.**		
Pepco Holdings Inc and Affiliates		No comment
Tacoma Power		None
Dynegy		No
Oncor Electric Delivery		No

Organization	Yes or No	Question 4 Comment
Company		

MOD-027 Overall Summary Consideration: The GVSDT received valuable feedback from stakeholders suggesting improvements to the standard.

Most stakeholders agreed with the inclusion of partial load rejection testing and the inclusion of the applicable footnote. As many stakeholders noted, the appropriate footnote in the posted version of the standard was footnote 4, rather than 5 – and is currently footnote 2 in the current draft of the standard. Based on the comments received, the GVSDT made the following clarifications and revisions:

1) **Numerous revisions made to clarify the language in Attachment 1, including adding row numbers. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1.**
2) **Revised sections 4.2.1, 4.2.2, and 4.2.3 to clarify the language.**
3) **Corrected numbering error of footnotes 4 and 5.**
4) **Corrected language in the footnote associated with partial load rejection, changing "on-load data" to "on-line data"**
5) **Reformatted sub part 2.1.1 that breaks the three alternatives for acquiring the unit MW response for model verification into 3 bullets instead of listing all three in a sentence.**

Stakeholders were evenly divided in their opinions regarding the periodicity aspects of Attachment 1. The GVSDT received suggestions for improvements which include the following:

1) **Numerous revisions were made to clarify the language in Attachment 1.**
2) **Row numbers were added to Attachment 1.**
3) **The following text was removed from R2: "within 365 calendar days from the date that the response was recorded".**
4) **In Attachment 1, the column title was revised from "Comments" to "Required Action".**
5) **Removed 25/50/75/100% phase in allowing GOs to install MW Recorders. This phase in unnecessarily complicated the Implementation Plan considering the vast majority of units already have recorders or processes in place where MW response can be recorded and provided (from plant DCS systems, recorders, SCADA data, etc). Note that low resolution data, approximately one sample per second, is adequate for turbine/governor and load control or active power/frequency control function model verification.**

There was a lot of industry confusion regarding the GVSDT attempt to effectively propose an exemption for base load units as the term "base load units" per say did not appear in the draft of the standard. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.

Stakeholders provided many suggestions for revisions to the standard. The following revisions were made by the GVSDT:

1) **A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
2) **For clarity and ease of reading, a paragraph within R3 was moved to the end of the requirement.**
3) **Changed "facility" to "unit" in Measures 2 and 4 to match the terminology in the requirements. Also, other minor clarifications and edits made in the Measures.**
4) **Changed "and" to "or" everywhere the phrase "and active power/frequency control functions" appears.**
5) **Revised R2 to remove "within 365 calendar days ......"**
6) **Revised R2.1.1 to specify "unit's MW model response".**
7) **Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.**
8) **Revised Attachment 1 extensively for clarity, including removing specificity regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.**
9) **Revised the Effective Dates, and subsequently the Implementation Plan, to mirror the Effective Dates in the current draft of MOD-026 (verification of Excitation Control Systems).**
10) **Removed an extra word "that" (just before the word accurately) in the Purpose statement.**
11) **The qualifier "directly connected" was applied at the top level of the Facilities section (A4.2) to emphasize direct connection to the BES.**
12) **The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.**
13) **The SDT revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 8) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 5)**

5. **The GVSDT has included partial load rejection testing in Part 2.1.1 subject to the conditions specified in footnote 5 (differences between the control mode tested and the final simulation model must be taken into account). Do you agree with the inclusion and footnote 5? If not, please explain in the comment area below.**

Summary Consideration: Most stakeholders agreed with the inclusion of partial load rejection testing and the inclusion of the applicable footnote. As many stakeholders noted, the appropriate footnote is footnote 4, rather than 5. Based on the comments received, the GVSDT made the following clarifications and revisions:

1) Numerous revisions were made to clarify the language in Attachment 1, including adding row numbers. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1.

2) Revised sections 4.2.1, 4.2.2, and 4.2.3 to clarify the language.

3) Corrected numbering error of footnotes 4 and 5 (in current draft of the standard, the partial load rejection footnote is Footnote 2).

4) Corrected language in footnote 2 of the current draft of the standard, changing "on-load data" to "on-line data"

5) Reformatted sub part 2.1.1 that breaks the three alternatives for acquiring the unit MW response for model verification into 3 bullets instead of listing all three in a sentence.

Organization	Yes or No	Question 5 Comment
Southwest Transmission Cooperative, Inc.	Negative	We are assuming the question really intended to reference footnote 4. **Unfortunately, the question should have referenced footnote 4. The GVSDT regrets the incorrect reference in the question. In current draft of the standard, the partial load rejection footnote is Footnote 2.** We appreciate the examples and believe they go a long way towards highlighting the drafting team's intent. However, we do not believe the examples are consistent with the requirements. We agree the examples are how the requirements should be implemented but we simply believe they have not documented the requirements in a way that is consistent with the examples. The first example does not seem to be

Organization	Yes or No	Question 5 Comment
		completely consistent with the standard and also contradicts itself. For instance, the language in Row 2 of the table in Attachment 1 states that the subsequent verification must occur within one year of the applicable unit's ten year anniversary of the previous collection date. This could be interpreted meaning it must occur between year 9 and 11. However, the example states (in the sixth sentence) that it must occur after the "10-year period" but then later on (in the eighth sentence) states that monitoring must begin for suitable events must begin "one year before the unit's 10-year anniversary date of the collection" of data per the Periodicity Table. **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If the unit is never running during a frequency excursion of the size listed, the GO can provide a statement to that effect in meeting the standard per a row that has been added to attachment 1.** Nothing in the table says anything about beginning monitoring Furthermore, it does not make sense to limit a Generator Owner to monitoring for events within one year data collection anniversary date. A Generator Owner should be free to collect data at more frequent periodicities. If they choose to update the model based on these periodicities, the "clock" for subsequent verifications should be reset. The standard should only require that the data is collected and model verified by the given date. **The GVSDT has attempted to clarify the table including incorporating your stated philosophy in only requiring that the model be verified by a certain date and is free to collect data at periodicities determined by the GO.** The example also seems to support the idea that "within one year" in the table is intended to be 9 to 11 years given that the subsequent data collection occurs between Years 10 and 11. We support the concept of beginning monitoring in year 9 for the second example but believe the standard language as written does not

Organization	Yes or No	Question 5 Comment
		support this concept. As a result, example 2 would appear to represent a compliance violation. Row 2 in the table in attachment 1 states "Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit's ten year anniversary" or to perform an "on-line speed governor reference change test or partial load rejection test". It does not say to begin monitoring. It is unequivocal that the subsequent test must occur within 11 years given the language. We suggest updating the table language to clarify that an entity must be begin monitoring for frequency excursion events in Year 9 but one may not be recorded until well after 10-year anniversary (including more than a year). **The GVSDT attempted to clarify the table. Of course the standard sets the periodicity, and the examples are not part of the standard but were provided to attempt to clarify. The GVSDT removed reference to when monitoring equipment is to be installed, as that is considered part of the "how" rather than the "what".** Example 4 helps highlight the issues of the language in the standard. Row 6 requires the Generator Owner to record the "first frequency excursion event that meets Criteria 1". Row 2 of the table requires that a frequency excursion event that meets Criteria 1 must be recorded "within one year of the of the applicable unit's ten year anniversary date". From row 6 and the examples, it would appear the drafting team intended this to begin monitoring within one year to record the first frequency excursion event that meets Criteria 1. We agree with this concept and suggest modifying row 2 language to: "Record unit Real Power response for first frequency excursion event that meets Criteria 1 no later than the ninth anniversary date of the collection of the recorded unit Real Power response used for current validation." This language will clarify that an event earlier than the ninth anniversary may be used and also clarify that first frequency event after the ninth anniversary must be used (if an earlier event is not voluntarily used) without limiting that the event must occur within Years 9 and 11. **The GVSDT believes the Attachment 1 has been revised to correct the issues you note.**

Organization	Yes or No	Question 5 Comment
		We also believe the examples should be added to the standard as an attachment. Otherwise, they will not be part of the standard and the drafting team's intent could be lost to an auditor. **The GVSDT chose not to include the examples in the standard because examples cannot capture every possible situation, and the language in the standard needs to be clear and unambiguous. The GVSDT has reformatted the attachment in an attempt to clarify.** We are concerned that much of the "Or" language in the Periodicity Table regarding waiting to observe a frequency excursion or perform an on-line speed governor reference change test or partial load rejection test could be interpreted as requiring one of these two tests if a frequency excursion is not observed within the appropriate time frame. We believe the language needs to be clarified that a Generator Owner is not required to stage a test if no frequency excursion event is observed. **The GVSDT has attempted to clarify the attachment.** Conceptually, we agree with the concept of an exemption. However, it is not clear to us where this exemption is located within the standard and how it would even apply. Given the penetration of large amounts of wind and record low natural gas prices, many units that might traditionally be based load might actually operate below the maximum capabilities frequently. Our first question then, is what does it mean to be based loaded and what units qualify? Second, what does an exemption mean? Does it mean that a frequency excursion does not have to be observed or an on-line speed governor reference change test or partial load rejection test does not have to be performed? If so, does a model still have to be provided? Any exemption must be explicitly clear to avoid ambiguity and to ensure that auditors will interpret the exemption in the same manner as registered entities. **We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified**

Organization	Yes or No	Question 5 Comment
		Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. We believe that this standard is overly administrative by memorializing the interactions between the Generator Owner and Transmission Planner that occur to model the generator's turbine/governor and load control and active power/frequency control systems. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. The FFT process represents one such effort to eliminate these backlogs. Interestingly, within the approval order for FFT, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard. Requirement R3 allows a Generator Operator to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems can be left unsolved. It should be struck. **Requirement R3 is a "peer review" type requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process received over whelming support by Industry based on their responses in prior postings.**

Organization	Yes or No	Question 5 Comment
		We are not convinced Requirement R4 is needed. The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of applicable control system changes. **Requirement R4 specifies the need for model verification due to changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic. Without Requirement R4, there would be no trigger between the standard 10 year periodicity to update the model to reflect changes to the turbine/governor system. Attachment 1 addresses the required periodicity and acceptable time delays to remain compliant.** In the first bullet under Requirement R3, we suggest referencing Requirement R5 regarding “useable” to make it clear that useable is in essence defined in Requirement R5. Otherwise, the reader may not realize that Requirement R5 sets the parameters on what “useable” is. We do not believe simply putting useable in quotes is enough. **The GVSDT thanks you for the comments. There is already a reference to Requirement R5 in the same bullet and GVSDT thinks it is not necessary to repeat it.** The numbering of the section 4.2 is not consistent with the parallel MOD-026-1 standard. MOD- 026-1 uses numbers for each sub-section while this standard uses primarily bullets. It would be easier to reference and comment if num **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the standard applicability to provide added clarity.**

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Please see responses above.		
Northeast Power Coordinating Council	No	The footnote regarding partial load rejection testing is footnote 4, not 5. The footnote should be removed and the language in 2.1.1 be revised. o 2.1.1 Documentation comparing the applicable unit's model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.** **Regarding the suggested formatting of the text for Part 2.1.1, the GVSDT implemented the suggested format with some verbiage alterations and has retained the footnote regarding additional details for the partial load rejection test. The SDT believe that additional qualification details for the partial load rejection test are most appropriately conveyed in a footnote.** **There was indeed a problem with the numbering of the footnotes, which has been addressed. The text of the footnote has been revised.**		

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	No	BPA believes that partial load rejection is not a suitable test for validating on-line governor response. Most turbine controls, including digital, analog, and mechanical, have different sets of settings for on-line and off-line, and often isolated operations. The settings are quite different, therefore, BPA believes using off-line settings for on-line studies is incorrect. Recording under-frequency events is the preferred approach for governor response validation. BPA recommends removing partial load rejection as an acceptable approach for governor response validation.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
Dominion- NERC Compliance Policy	No	Footnotes should not contain requirements. If necessary, then they should be moved into the requirements section (i.e. Footnote 4). Against giving the option of purposefully causing system disturbance (i.e. load rejection). It is unclear how this would benefit the reliability of the BES compared to the two other data collection methods available.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for		

Organization	Yes or No	Question 5 Comment
online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.** **The GVSDT believes that the footnote is just a clarification regarding the potential use of a partial load rejection test and it is not a requirement.** **Also, it should be noted that the partial load rejection test is not meant as a system disturbance (to produce an under-frequency event to verify the models of the units that remained online). The partial load rejection is a staged test that, under certain conditions, could be applied for the verification of the turbine/speed governor model of the unit undergoing the partial load rejection.**		
PPL	No	Comments: a. The referenced footnote is number 4, not 5. R2.1.1 and the verification table later in the standard allow the alternative of an on-line speed governor reference change test. In any event the standard requires that, if a naturally-occurring disturbance meeting Criterion 1 does not occur within the specified ambient-monitoring period, we must create one. We are opposed to making it mandatory that GOs conduct such testing. An on-line speed governor reference change test is not always possible. Where it is possible there is risk of creating a larger-than-desired disturbance, possibly threatening grid stability or tripping the generation unit. At the very least there would be a shock to the equipment and some loss of life. The same applies for a partial load-rejection test. It is meanwhile unclear how invasive such episodes would be. Power Technologies, in their paper “Testing Methods, An Overview,” states that five episodes may be required. These are expected to be hard trips, in which case the data gathered may be less useful than the GVSDT is expecting. Rejection to house load, followed by rapid re-synchronization, cannot be expected because need to avoid overspeed due to full-load rejections requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. This is an unreasonable

Organization	Yes or No	Question 5 Comment
		burden to place on GOs, especially when there has not been any commensurate reliability benefit identified. The rationale in MOD-027-1, "to ensure modeling data is accurate," is far from compelling, nor is it explained why the accuracy of our present, OEM-generated data should not be equal-to or better than that identified via testing. **The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation.** **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.** **The GVSDT understands that many turbine/speed governor controllers do not provide access to the speed reference setpoint and/or the ability to apply a step (or similar test signal) to the speed reference setpoint.** **On the other hand, if a test signal can be added to the speed reference setpoint, this test is quite safe and should not pose any risks to the equipment, to the stability of the grid or causing a trip of the unit being tested. For a speed governor with 5% droop, a 0.5% change in speed reference setpoint would result in (approximately) 10% change in MW power output of the unit. Thus, it is reasonably easy to calibrate the test signal being applied to avoid risks to the unit. Criteria 1 in Attachment 1 is somewhat equivalent to changes in speed reference setpoint in the order of 0.1% (Eastern Interconnection), 0.16% (Western and ERCOT Interconnections) and 0.25% in Quebec Interconnection.** **There is a documented discrepancy between the simulation models for**

Organization	Yes or No	Question 5 Comment
		turbines/speed governors and the actual (recorded) response of the different Interconnected Systems to disturbances resulting in frequency deviations. One such reference is the Special Publication "Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns," IEEE PES Special Publication 07TP180, May 2007. **There was indeed a problem with the numbering of the footnotes, which has been addressed. The text of the footnote has been revised.** b. The response adjustment described in footnote 4 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide high-speed recordings of responses to grid disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is there any purpose to making GOs develop models or en masse hire consultants to do so. **The generator entity is responsible for ensuring that the turbine/speed governor model response matches the response from a recorded disturbance. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits.** **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner.** **Also, the Generator Owner can acquire the services of the TP or TO to assist in model verification, however, the Generator Owner will be responsible for model**

Organization	Yes or No	Question 5 Comment
		verification from a compliance perspective.
Response: Thank you for your comment. Please see responses above.		
Consolidated Edison Co. of NY, Inc.	No	We believe the footnote regarding partial load rejection testing is footnote 4, not 5. We recommend the footnote be removed and the language in 2.1.1 be revised.2.1.1: This requirement needs additional clarity. In one sentence, 2 on-line options and 1 off-line testing option have been proposed that compare the actual response to the model response. We recommend the following edits which provide more clarity and eliminate Footnote 4. o 2.1.1 Documentation comparing the applicable unit's model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		

Organization	Yes or No	Question 5 Comment
Regarding the suggested formatting of the text for Part 2.1.1, the GVSDT implemented the suggested format with some verbiage alterations and has retained the footnote regarding additional details for the partial load rejection test. The SDT believe that additional qualification details for the partial load rejection test are most appropriately conveyed in a footnote. **There was indeed a problem with the numbering of the footnotes, which has been addressed. The text of the Footnote has been revised.**		
Independent Electricity System Operator	No	Footnote 5 as written contains requirements that are in addition to Part 2.1.1 as opposed to provide clarification or explain the testing process. We suggest that the requirements in Footnote 5 be put into Part 2.1.1 or its sub-part. We also suggest that the language be made clearer, in particular the use of the word “load” in “load rejection”, “load or set point control”, and “on load” which is very confusing.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.** **The GVSDT believes that the footnote is just a clarification regarding the potential use of a partial load rejection test and it is not a requirement. Note that the text of the footnote has been revised to correct a typo (on-load data changed to on-line data)**		
Public Service Enterprise Group (PSEG)	No	Footnote 4, not Footnote 5, addresses the question. Typo in Footnote 4: The word “on” should be deleted in this phrase in the last sentence: “...if the final model is not validated from on load date under...”
Response: The GVSDT thanks you for your comment. There was indeed a problem with the numbering of the footnotes, which has		

Organization	Yes or No	Question 5 Comment
been addressed. The text of the Footnote has been revised.		
Public Utility District No. 1 of Clark County	No	My Utility's only generator is a combustion turbine with a steam turbine and generator all attached to one shaft. Any load rejection event decreases the life of the components and should be avoided unless absolutely necessary. While partial load rejection testing may not significantly impact other forms of generation (i.e. hydro) the GVSDT needs to exercise caution in using simulated load rejection as a means of testing generator response.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **In the case of a single-shaft combined-cycle unit like the example described in this comment, the GVSDT believes that a partial load rejection test would not be applicable. And, as such, the verification of the models would have to rely on the other options in Part 2.1.1 (frequency excursion from a system disturbance or a speed governor speed reference step change.** **Note that the text of Footnote 5 (Footnote 2 in the current draft of the standard) has been revised to correct a typo (on-load data changed to on-line data)**		
Wisconsin Electric Power Company	No	There is not nearly enough confidence that governor testing on a unit connected to the system is safe or desirable, whether it is partial load testing or a change in the speed governor reference. Footnote 4 seems to make the value of any online testing very questionable. NERC should work with turbine-generator and controls suppliers (OEM's) to validate the concept of online testing of governor controls. The use of recorded data during frequency excursions also requires more information on what would constitute adequate data. In summary, more work on such a requirement for online testing is needed, as well as collaboration with equipment suppliers.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation.

The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.

The GVSDT understands that many turbine/speed governor controllers do not provide access to the speed reference setpoint and/or the ability to apply a step (or similar test signal) to the speed reference setpoint.

On the other hand, if a test signal can be added to the speed reference setpoint, this test is quite safe and should not pose any risks to the equipment, to the stability of the grid or causing a trip of the unit being tested. For a speed governor with 5% droop, a 0.5% change in speed reference setpoint would result in (approximately) 10% change in MW power output of the unit. Thus, it is reasonably easy to calibrate the test signal being applied to avoid risks to the unit. Criteria 1 in Attachment 1 is somewhat equivalent to changes in speed reference setpoint in the order of 0.1% (Eastern Interconnection), 0.16% (Western and ERCOT Interconnections) and 0.25% in Quebec Interconnection.</td></tr>
<tr><td>Ameren</td><td>No</td><td>We agree with the inclusion of an additional option, but find this footnote to be a concern. The footnote is too vague and provides no guidance on an appropriate model, the acceptable quantitative differences or any way for a GO to benchmark the adequacy of its verification.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation.

The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
Alberta Electric System Operator	No	The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
Seattle City Light	No	It appears but is unclear if a partial load rejection test is acceptable. The unit on-line test is difficult to capture without functioning Digital Fault Recorders, which are not available at all plants. Seattle City Light requires a clarification in the text if on-line testing required or is a partial load rejection test allowed.
Response: The GVSDT thanks you for your comment. Part 2.1.1 states that the verification may be accomplished by one of the following methods: the recorded response to a system frequency excursion, an on-line governor reference change, or a partial load rejection test. **The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation.** **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
American Electric Power	No	AEP is not certain that load rejection testing would be an acceptable means of verification, particularly given that a unit is disconnected from the system and the

Organization	Yes or No	Question 5 Comment
		issues alluded to in the footnote. Is the drafting team completely confident that this is an appropriate means of verification and could not produce a mischaracterization of unit behavior during system frequency excursions?
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
Georgia Transmission Corporation	No	Why not model what was tested?
Response: The GVSDT thanks you for your comment. The GVSDT understands that the question is related to why not model the speed governor as tested, for instance, based on a partial load rejection. With this understanding in mind, the answer is simple: because quite often the response following a partial load rejection has a different dynamic characteristic than what would be the response while in service, synchronized to the grid. Therefore, a model validated based on this different dynamic response would be incorrect to represent the expected performance of the equipment while connected to the grid.		
Seattle City Light	No	It appears but is unclear if a partial load rejection test is acceptable. The unit on-line test is difficult to capture without functioning Digital Fault Recorders, which are not available at all plants. Seattle City Light requires a clarification in the text if on-line testing required or is a partial load rejection test allowed.
Response: The GVSDT thanks you for your comment. Part 2.1.1 states that the verification may be accomplished by one of the following methods: the recorded response to a system frequency excursion, an on-line governor reference change, or a partial load rejection test. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is		

Organization	Yes or No	Question 5 Comment
not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
Tacoma Power	Yes	The question above should have referenced footnote 4.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4. The GVSDT regrets the incorrect reference in the question.		
ACES Power Standards Collaborators	Yes	We are assuming the question really intended to reference footnote 4.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4. The GVSDT regrets the incorrect reference in the question.		
Southern Company	Yes	The footnote number in the clean version is Footnote 4. The footnote reflects our concerns about the validity of data taken from partial load rejection testing when compared to the unit response during normal operating load levels.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
South Carolina Electric and Gas	Yes	The footnotes in the redline and clean versions of MOD-027-1 have different numbering.

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the standard. The GVSDT regrets the incorrect reference in the question.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that there must be viable options available in the event that a frequency excursion of the appropriate magnitude was not captured during the validation time frame. This may be more applicable to smaller generation facilities, or those which have a small capacity factor and are rarely online. We also agree that some further analysis may be required to account for the difference in operating conditions as described in the footnote.
Response: The GVSDT thanks you for your comment. The intent of Part 2.1.1 is to offer these alternatives and the GVSDT believes that any of these options, when applicable, would lead to the desired result: a verified model.		
Xcel Energy	Yes	The footnote that should be referenced in the question is Footnote 4. Xcel agrees that the control mode differences when using a partial load rejection must be identified.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the posted standard. The GVSDT regrets the incorrect reference in the question.		
SERC Planning Standards Subcommittee		Please check footnote numbering. Footnote 5 in the redline version is labeled footnote 4 in the clean version.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the standard. The GVSDT regrets the incorrect reference in the question.		
Cowlitz County PUD		Cowlitz respectfully asks that the Standard number be referenced in multiple standard comment forms. Did you mean footnote 4? As a small GO, Cowlitz would have to hire a consultant to comment on this question, and therefore must defer to larger GO's who have the appropriate subject matter experts available.

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the standard. The GVSDT regrets the incorrect reference in the question.		
Southwest Power Pool Standards Development Team	Yes	
FirstEnergy	Yes	
Puget Sound Energy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	
Luminant Power	Yes	

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	Yes	
Los Angeles Department of Water and Power	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Exelon	Yes	
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
American Wind Energy Association	Yes	
Kansas City Power & Light	Yes	
SERC Generation Subcommittee		No comment
SERC Dynamic Review Subcommittee (DRS)		No comment

Organization	Yes or No	Question 5 Comment
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.
Indiana Municipal Power Agency		No comment

6. **The GVSDT has provided guidance on the periodicity aspects of Attachment 1. Do you agree? If not, please explain in the comment area below.**

Summary Consideration: Stakeholders were evenly divided in their opinions regarding the periodicity aspects of Attachment 1. The GVSDT received suggestions for improvements which include the following:

1) Numerous revisions were made to clarify the language in Attachment 1.

2) Row numbers were added to Attachment 1.

3) The following text was removed from R2: "within 365 calendar days from the date that the response was recorded".

4) In Attachment 1, the column title "Comments" was changed to "Required Action".

5) The 25/50/75/100% phase in allowing GOs to install MW Recorders was removed from the standard. This phase in unnecessarily complicated the Implementation Plan considering the vast majority of units already have recorders or processes in place where MW response can be recorded and provided (from plant DCS systems, recorders, SCADA data, etc). Note that low resolution data, approximately one sample per second, is adequate for turbine/governor and load control or active power/frequency control function model verification.

Organization	Yes or No	Question 6 Comment
BC Hydro and Power Authority	Negative	BC Hydro is voting Negative as the motivation and purpose for the 10 year recurring validation period is not clearly defined. BC Hydro recommends either supplying better supporting justification, or consideration should be given to modify this criteria, ie remove the blanket 10 year requirement. In place of the blanket interval, alternative criteria recommended are a) for machines equipped with digital excitation and governor control, no recurring testing required because there is nothing that can change (software doesn't drift), b) for machines with either or both non-digital exciter and governor control, recurring testing should be required every X years (analog control is more susceptible to setting drift and other issues) BC Hydro supports the remaining reasons for requiring validation.

Organization	Yes or No	Question 6 Comment
Response: The GVSDT thanks you for your comment. The SDT believes that the 10 year periodicity is appropriate and has received industry support for this concept, specifically as a result of the first posting. Digital excitation systems settings can be modified, and there are other components in the closed loop system that can degrade with heat and stress over time (SCRs, discrete electronic components, hydraulic components, etc). **In the specific case of turbine/speed governor controls, there are many mechanical or hydraulic components that could degrade over time, despite having a digital controller. Thus, the GVSDT considers that periodic re-validation is necessary.**		
Consumers Energy	Negative	The generator model with the excitation system and the load rejection testing or frequency step response testing is difficult to perform and has possibilities of damaging equipment and causing reliability issues on the system in order to perform.
Response: The GVSDT thanks you for your comment. MOD-027 is written to allow for the use of ambient monitoring, recorded data associated with the normal operation of your equipment. A GO with your concerns can alleviate the issues you mention using ambient monitoring.		
Public Utility District No. 1 of Lewis County	Negative	Thank you for the opportunity to comment on the proposed standard MOD-027-1. Our utility owns and operated a smaller run-of-river hydroelectric plant with two 35MW units. The testing required in the proposed standard is onerous and quite expensive for small GO. In April 2009, we tested our 2 generating units and submitted to WECC the results of the generator validation results and subsequently received a certificate of compliance. Since we recently completed model certification, is the next date 10 years from completion or 2019? **You are correct, the standard is written to allow you to use the prior test for the initial period if it complies with the requirements. Please see the Attachment 1 "Consideration for Early Compliance". The GVSDT has attempted to improve the clarity of Attachment 1.** The MOD-027 Attachment 1 is unclear in this regard. I believe the model testing can be spread out even further than 10 years, especially for the smaller units (less than 100MVA) and plants, say every 20 years. Most of the parameters collected do not

Organization	Yes or No	Question 6 Comment
		change and are related to the construction of the generation unit. Standard unit models for hydro are close enough without the testing. Making small plants go through this exercise is overkill. Maybe WECC should have a standard model test group and take care of this testing for small plants. **The standard drafting team considered what the periodicity should be and decided that 10 years is appropriate (and it is actually a longer period than currently required by WECC). It is important that there be periodic model validation. Even if no equipment changes are made, a review of the model may point out errors that have crept into the model over time. The standard does also recognize plant size and does not require model verification for plants smaller than the given size for the interconnection. The model verification needs to be the responsibility of entities that have physical access to the equipment although they may bring others in to assist.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
SERC Dynamic Review Subcommittee (DRS)	No	Regarding the terminology in Attachment 1, “Turbine/governor and load control and active power/frequency control”, should all the “and”s in the Event Triggering Verification column be “or”s? The DRS recommends that this be reviewed for consistency.
Response: The GVSDT thanks you for your comment. The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The SDT has corrected the inadvertent use of the last “and” by changing it to an “or” (Turbine/governor and load control or active power/frequency control).		
Tacoma Power	No	Attachment 1, especially the column titled “Verification Periodicity” is difficult to interpret. For example, for the “Event Triggering Verification” row titled “Initial verification for a new applicable unit...” the periodicity is stated as “Record unit Real Power response to first frequency excursion.... OR record unit Real Power response for....reference change....no more than 365 calendar days from the commissioning date”. This language implies that there is no stated periodicity applied if the

Organization	Yes or No	Question 6 Comment
		generator owner elects the frequency excursion event option. Rather the generator owner must interpret that such an event has occurred, even if it happens 15 years later, and then has 365 calendar days to verify the model. The periodicity as applied to existing fleet and new/changed fleet should be made easier to interpret.
Response: The GVSDT thanks you for your comment. The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.		
Florida Municipal Power Agency	No	The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.** - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? **Your interpretation is correct, however, since each interconnection has several events a year that meet the frequency deviation threshold for verification, it is**

Organization	Yes or No	Question 6 Comment
		unlikely that the unit would not be running for all of them. On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? **If there is no event when the equipment is available, the GO can submit a statement to that effect. A row was added to Attachment 1 to provide for that circumstance.** We recommend numbering the rows in the table so that row references are clear. **The GVSDT has added row numbers.**
City of Vero	No	The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.** - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? **Your interpretation is correct, however, since each interconnection has several**

Organization	Yes or No	Question 6 Comment
		events a year that meet the frequency deviation threshold for verification, it is unlikely that the unit would not be running for all of them. - On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? **If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.** We recommend numbering the rows in the table so that row references are clear. **The GVSDT has added row numbers.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
PPL	No	We must wait for naturally-occurring disturbances, if not creating upsets of our own, making it impossible to guarantee up-front that the 25%-3 yrs, 50% - 5 yrs etc requirements will be met. Such requirements also conflict with the instruction in the periodicity table to, “Record unit Real Power response to the first frequency excursion event that meets Criteria 1 on or after the Standard Implementation Effective Date.” **You are correct, and the GVSDT added a row to the table to account for the circumstance where no event occurs while the generator is in service.** The row in the same table for, “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period, and neither an on-line speed governor reference test nor a partial load rejection test was performed,” meanwhile appears to pertain to circumstances that are not permitted by this standard. **The SDT recognizes that the table is hard to understand and has attempted to**

Organization	Yes or No	Question 6 Comment
		reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.
Response: The GVSDT thanks you for your comment. Please see responses above.		
ACES Power Standards Collaborators	No	We appreciate the examples and believe they go a long way towards highlighting the drafting team's intent. However, we do not believe the examples are consistent with the requirements. We agree the examples are how the requirements should be implemented but we simply believe they have not documented the requirements in a way that is consistent with the examples. The first example does not seem to be completely consistent with the standard and also contradicts itself. For instance, the language in Row 2 of the table in Attachment 1 states that the subsequent verification must occur within one year of the applicable unit's ten year anniversary of the previous collection date. This could be interpreted meaning it must occur between year 9 and 11. However, the example states (in the sixth sentence) that it must occur after the "10-year period" but then later on (in the eighth sentence) states that monitoring must begin for suitable events must begin "one year before the unit's 10-year anniversary date of the collection" of data per the Periodicity Table. **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If the unit is never running during a frequency excursion of the size listed, the GO can provide a statement to that effect in meeting the standard per a row that has been added to attachment 1.** Nothing in the table says anything about beginning monitoring. Furthermore, it does

Organization	Yes or No	Question 6 Comment
		not make sense to limit a Generator Owner to monitoring for events within one year data collection anniversary date. A Generator Owner should be free to collect data at more frequent periodicities. If they choose to update the model based on these periodicities, the "clock" for subsequent verifications should be reset. The standard should only require that the data is collected and model verified by the given date. **The GVSDT has attempted to clarify the table including incorporating your stated philosophy in only requiring that the model be verified by a certain date and is free to collect data at periodicities determined by the GO.** The example also seems to support the idea that "within one year" in the table is intended to be 9 to 11 years given that the subsequent data collection occurs between Years 10 and 11. We support the concept of beginning monitoring in year 9 for the second example but believe the standard language as written does not support this concept. As a result, example 2 would appear to represent a compliance violation. Row 2 in the table in attachment 1 states "Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit's ten year anniversary" or to perform an "on-line speed governor reference change test or partial load rejection test". It does not say to begin monitoring. It is unequivocal that the subsequent test must occur within 11 years given the language. We suggest updating the table language to clarify that an entity must be begin monitoring for frequency excursion events in Year 9 but one may not be recorded until well after 10-year anniversary (including more than a year). **The GVSDT attempted to clarify the table. Of course the standard sets the periodicity, and the examples are not part of the standard but were provided to attempt to clarify. The GVSDT removed reference to when monitoring equipment is to be installed, as that is considered part of the "how" rather than the "what".** Example 4 helps highlight the issues of the language in the standard. Row 6 requires the Generator Owner to record the "first frequency excursion event that meets Criteria 1". Row 2 of the table requires that a frequency excursion event that meets Criteria 1 must be recorded "within one year of the of the applicable unit's ten year

Organization	Yes or No	Question 6 Comment
		anniversary date". From row 6 and the examples, it would appear the drafting team intended this to begin monitoring within one year to record the first frequency excursion event that meets Criteria 1. We agree with this concept and suggest modifying row 2 language to: "Record unit Real Power response for first frequency excursion event that meets Criteria 1 no later than the ninth anniversary date of the collection of the recorded unit Real Power response used for current validation." This language will clarify that an event earlier than the ninth anniversary may be used and also clarify that first frequency event after the ninth anniversary must be used (if an earlier event is not voluntarily used) without limiting that the event must occur within Years 9 and 11. **The GVSDT believes the Attachment 1 has been revised to correct the issues you noted.** We also believe the examples should be added to the standard as an attachment. Otherwise, they will not be part of the standard and the drafting team's intent could be lost to an auditor. **The GVSDT chose not to include the examples in the standard because examples cannot capture every possible situation, and the language in the standard needs to be clear and unambiguous. The GVSDT has reformatted the attachment in an attempt to clarify.** We are concerned that much of the "Or" language in the Periodicity Table regarding waiting to observe a frequency excursion or perform an on-line speed governor reference change test or partial load rejection test could be interpreted as requiring one of these two tests if a frequency excursion is not observed within the appropriate time frame. We believe the language needs to be clarified that a Generator Owner is not required to stage a test if no frequency excursion event is observed. **The GVSDT has attempted to clarify the attachment and believes that the revisions will address your comment.**

Organization	Yes or No	Question 6 Comment
Response: The GVSDT thanks you for your comment. Please see responses above.		
Puget Sound Energy	No	This periodicity would ideally be the same as MOD 25 and MOD 26 since this testing, at least in the WECC region, is all done at the same time. **The periodicity in the current drafts of MOD-026 and MOD-027, both dynamic model verification standards, are the same in the current draft of the standard. MOD-025 is a steady state model verification and is fundamentally different and requires fundamentally different expertise.** Also it is not clear to find the ten year re-test requirement in Attachment 1, in fact it just seems inferred. If it is a ten year re-testing requirement, it should be more clearly stated in one of the requirements. **The GVSDT attempted to clarify by adjusting formatting and revising Attachment 1.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Southern Company	No	a) R2 references Attachment 1 for periodicity, yet also includes a "365 day" statement. Please rely on Attachment 1 for the periodicity information and remove the parenthetical element from R2. **The GVSDT has attempted to make revisions to Requirement R2 and attachment to clarify the intent, including deleting the "365 day" statement.** b) On first glance, it is not clear that pages 14-18 all comprise Attachment 1 - please label each table. **The GVSDT has attempted to reformat the table to provide better clarity, including an "Attachment 1" header on each page of Attachment 1.** c) Please number the rows of the table so that they can be easily referred to. **The GVSDT has numbered the rows.** d) The GO is not aware of system frequency excursion events at each of their

Organization	Yes or No	Question 6 Comment
		facilities to see if a Criteria 1 has occurred. **The GVSDT anticipates that NERC will maintain a list of frequency excursion events for each interconnection that is accessible to each GO. The Generation Verification SDT is closely following and coordinating with the Frequency Response SDT. It is hoped that the Frequency Response SDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, though the Frequency Response SDT has discussed this concept and is investigating the use of a tool to help facilitate the identification of appropriate frequency excursions, the process is still evolving. As an interim step, the Generation Verification SDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine/governor and load control functions for the purpose of model verification and b) would be expected to occur 15 times a year or more. If by chance a process identifying frequency excursions that can be utilized in support of standard MOD-027-1 requirements is not developed by the Frequency Response SDT, then such a process will have to be proposed for future revision to standard MOD-027-1 by the Generation Verification SDT** e) should row 1 of the table on p 15 include "existing applicable unit"? **The GVSDT revised Attachment 1 in an attempt to provide better clarity.** h) Row 2 should be labeled "Recurring verifications" as "for an existing applicable unit" is superfluous to subsequent. **The GVSDT has attempted to improve the clarity of Attachment 1.** i) What is the time frame for the Criterion 1 frequency deviation? **The Criterion 1 frequency deviation pertains to the nadir and the GVSDT has revised the reference in Attachment 1 to improve the clarity.** j) Row 4 of the table describes what is commonly termed "sister" units - the

Organization	Yes or No	Question 6 Comment
		limitation to allow sisterhood for only those units at the same physical location should be relaxed to include all identical units for the same GO/GOP either within a Balancing Area, or alternatively, within the area of responsibility for a Reliability Coordinator. The GO should be allowed to take credit for units located within the same Balancing Area (or alternatively the Reliability Coordinator area of responsibility) if he can show that the physical location is not a factor in the comparison. **The GVSDT notes the general agreement among industry with using the proxy unit approach. The GVSDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** k) It is not possible to comply with the R2 25/50/75/100% in 3/5/7/9 year implementation plan and fulfill the trigger verification of Row 5 of Attachment 1 table. **The GVSDT has attempted to revise the statement of the requirement including attachment 1 to clarify that if no suitable events occur, documentation of that condition will suffice. Also, the SDT removed the 25/50/75/100% phase in proposed to allow GOs to install MW Recorders over a period of several years. This phase in unnecessarily complicated the Implementation Plan considering that the vast majority of units already have recorders or processes in place where unit MW response to frequency excursions can be recorded and provided (from plant DCS systems, recorders, SCADA data, etc). Note that for units that need to acquire recorders, slow resolution data, approximately 1 sample per second, is adequate**

Organization	Yes or No	Question 6 Comment
		for turbine/governor and load control or active power/frequency control function model verification.
Response: The GVSDT thanks you for your comment. Please see responses above.		
ExxonMobil Research and Engineering	No	A model's validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit's response.
Response: The GVSDT thanks you for your comment. The subject models need to reflect operating modes, installation of load controllers in plants, etc. Periodic model verification is needed to ensure that a model review is performed periodically to capture the effects of changing situations, in addition to the initial verification and triggered verifications. The GVSDT believes the 10 year periodicity provides for appropriate periodic model verification.		
Public Service Enterprise Group (PSEG)	No	For ease of reference, we suggest that the three examples in the Background section of the Comment form be incorporated into Attachment 1 or as a separate attachment in the standard.
Response: The GVSDT thanks you for your comment. The GVSDT has elected to omit the examples from the standard because the examples cannot capture all possible situations and may mislead. The standard needs to be clear and unambiguous.		
Manitoba Hydro	No	See comment (3) provided in Question 8.
Response: The GVSDT thanks you for your comment. The response to your question follows your comment in Question 8.		
Los Angeles Department of Water and Power	No	The criteria "Consideration for Early Compliance" seems to parallel the language for the draft of MOD-026-1 which deleted the redundant statement of, "The Generator Owner has an existing verified model that is compliant with the requirements of this

Organization	Yes or No	Question 6 Comment
		standards." It is understood that the applicable entity is compliant if it meets this criteria.
Response: The GVSDT thanks you for your comment. The GVSDT has checked the wording so that the Consideration for Early Compliance wordings is consistent between MOD-026 and MOD-027.		
Wisconsin Electric Power Company	No	When it takes five pages to describe the periodicity requirements, the standard is overly complicated.
Response: The GVSDT thanks you for your comment and has attempted to clarify and simplify the statement of the periodicity requirement in Attachment 1.		
Ameren	No	(1)We believe that any testing or verification required by MOD-012, MOD-013, MOD-026 and MOD-027 should have the same periodicity so that all required tasks can be performed in parallel. Note that earlier we have suggested a 10 year cycle. (2)We believe Attachment 1, row 4 is intended to allow "sister unit" testing so plants with multiple identical units are not required to verify each identical unit during each verification cycle. If this is the case, please clarify this option more clearly in the Attachment or the Standard.
Response: The GVSDT thanks you for your comment. MOD-012 and MOD-013 are data submittal requirements only, fundamentally different from the draft MOD-026 and 027 model verification standards – thus identical periodicities will not result in any efficiencies. We appreciate your support of the GVSDT 10 year periodicity. You are correct with regard to the "sister unit" policy. The GVSDT has attempted to revise Attachment 1 to improve clarity.		
Seattle City Light	No	Once every ten years seems reasonable with load rejection testing, but it is unclear if frequency excursion modeling is required during operation.
Response: The GVSDT thanks you for your comment. The GVSDT attempted to specify what had to be done, but to leave decisions about how it is done to the verification expert. The GVSDT has revised Attachment 1 in an attempt to improve clarity.		

Organization	Yes or No	Question 6 Comment
Part 2.1.1 lists three possible methods of verifying governor response, one of which is recording the unit response to a system frequency excursion while the unit is on-line.		
American Electric Power	No	The Attachment 1 table is difficult to read, and the information contained could be more clearly conveyed than it currently is. The event triggers and periodicity span across multiple pages, making it a challenge to use effectively. Titling the column “Comments” does not properly describe the information that column contains. Suggest re-naming this column as “Action Required”. **The GVSDT has revised the Comments column title accordingly.** Within the section for “Subsequent verification for an existing applicable unit”, it is unnecessary and counter-intuitive to allow the resetting of the period to only occur “within one year of the applicable unit’s ten year anniversary date...”. This should be corrected to state that the verification period could be reset for any frequency excursion occurring “or before the 10 year anniversary date”. **The standard has been revised to clarify that the 10 year period is reset whenever a verification is completed.** Within the “Event Triggering Verification” column (page 16 of the clean version), how is the following combination not non-compliant? “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period” and “Neither an on-line speed governor reference test nor a partial load rejection test was performed”. **The table has been revised in an attempt to provide additional clarity and address your comment.** Attachment 1 has references to "Not required until responsive control mode operation for connected operations is established." AEP does not understand what this statement means. **This condition applies to units that change from being unresponsive to frequency deviations to being responsive to frequency deviations. If the normal operation**

Organization	Yes or No	Question 6 Comment
		mode is changed to being frequency responsive, a verification is triggered.
Response: The GVSDT thanks you for your comment. Please see responses above.		
Entergy Services, Inc	No	Regarding the terminology in Attachment 1, "Turbine/governor and load control and active power/frequency control", should all the "and"s in the Event Triggering Verification column be "or"s? Entergy recommends that this be reviewed for consistency.
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the "ands" and verified that they are used appropriately. The "ands" provide a limited specific condition which applies and triggers that table row. The "ands" in the phrase you quote are to be applied as explained in Footnote 1 and depend upon the equipment.		
Duke Energy	No	The Eastern Interconnection frequency excursion criteria of greater than or equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don't provide data that is nearly as meaningful as excursions at 0.06 or 0.07.
Response: The GVSDT thanks you for your comment. The standard provides the minimum deviation to use, and certainly a larger deviation would be better if available. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more.		
Georgia Transmission Corporation	No	We agree with the SERC DRS that the terminology in Attachment 1 be reviewed for consistency. Should the "and's" be "or's"? ("Turbine/governor and load control and active power/frequency control")
Response: The GVSDT thanks you for your comment. The "ands" in the phrase you quote are to be applied as explained in Footnote 1 and depend upon the equipment. The GVSDT reviewed the "and"s in the table to make sure they are used		

Organization	Yes or No	Question 6 Comment
appropriately.		
Seattle City Light	No	Once every ten years seems reasonable with load rejection testing, but it is unclear if frequency excursion modeling is required during operation.
Response: The GVSDT thanks you for your comment. The GVSDT attempted to specify what had to be done, but to leave decisions about how it is done to the verification expert.		
Ingleside Cogeneration LP	Yes	We support the efforts by all project teams to clearly define the implementation and subsequent periodic evaluation time frames - as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC's Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-027-1, we believe that the proposed intervals are sufficient to perform the frequency performance model validations; however they are initiated.
Response: The GVSDT thanks you for your supportive comment.		
Independent Electricity System Operator	Yes	We agree with the periodicity requirements. We respectfully point out once again that the periodicity criteria are not guidance, they part of Requirement R2 and must be complied with.
Response: The GVSDT thanks you for your supportive comment.		
Xcel Energy	Yes	Xcel Energy believes Attachment 1 describes more than periodicity and suggests that the first column be titled "Verification Condition" and the second column be titled "Verification Timeline" since several lines are describing how much time following an event or condition is available to complete verification (not the periodicity of the verification).
Response: The GVSDT thanks you for your comment. The GVSDT considered your comment and others and made significant		

Organization	Yes or No	Question 6 Comment
revisions in attempting to improve the clarity of Attachment 1.		
Exelon	Yes	Exelon appreciates the additional guidance provided in the Unofficial Comment Form for Project 2007-09, "Generator Verification," that includes specific examples for implementation to aid the industry in understanding the proposed model verification periodicity; however, Exelon is concerned that this information will be "lost" since it is only documented in this format. To ensure this guidance is available to registered entities in the future, Exelon suggests that this guidance, including the four examples, be added to the Implementation Plan for MOD-027-1. **The GVSDT chose not to include the examples in the standard because examples cannot capture every possible situation and may mislead, and the language in the standard needs to be clear and unambiguous. The GVSDT has reformatted the attachment 1 in an attempt to clarify.** The staggered implementation period in the current draft of MOD 027-1 and the additional guidance provided by the SDT, seems to imply, as substantiated by the examples provided above, that before the 1st model verification period at T=0 all recorders are required to be installed and ready to trigger in the case of an ambient event for each generating unit. Please clarify that the staggered implementation allows the applicable generating units to modify/install recording equipment at any time during the three year implementation period at the discretion of the Generator Owner and not that all applicable units should have the recording equipment installed and ready to trigger following regulatory approval of MOD-027-1. **We attempted to revise the Attachment 1 to provide better clarity. If the GO decides to use monitoring equipment they will need to make sure it is in place and ready to record in sufficient time to monitor ambient events. Attachment 1 was revised so that it no longer provides requirements for when monitoring equipment is installed. The test methods and details are left to the discretion of the expert. Also, a row has been added to table 1 to allow for the situation where no event is recorded that can be used for model verification – though in order to be able to**

Organization	Yes or No	Question 6 Comment
		qualify for the exemption to verify the model until the unit is subjected to a frequency event with the unit in the proper operating mode expected to govern, recorders must be in place before the effective date of the standard.
Response: The GVSDT thanks you for your comment. Please see responses above.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Dominion- NERC Compliance Policy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	

Organization	Yes or No	Question 6 Comment
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	
Luminant Power	Yes	
Public Utility District No. 1 of Clark County	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
AECI	Yes	
American Wind Energy Association	Yes	
Kansas City Power & Light	Yes	
Cowlitz County PUD		Cowlitz could not find the guidance.
Indiana Municipal Power Agency		No comment

Organization	Yes or No	Question 6 Comment
SERC Generation Subcommittee		No comment
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.

7. **The GVSDT has address units which are always base loaded (by definition a base loaded unit is considered verified). This provides an exemption from verification for base load units. Do you agree? If not, please explain in the comment area below.**

Summary Consideration: There was a lot of industry confusion regarding the GVSDT attempt to effectively propose an exemption for base load units as the term "base load units" per say did not appear in the draft of the standard. The GVSDT inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	Base loaded units could provide governor response for over-frequency events and should have verified models for this event. The term "base loaded" is not defined in MOD-027.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
SERC Dynamic Review Subcommittee (DRS)	No	The DRS sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Bonneville Power	No	BPA believes that the Generator Owner needs to provide evidence that a generating

Organization	Yes or No	Question 7 Comment
Administration		unit is operated as base loaded. It will be very useful to clarify the "base loaded" terminology as operating with control valves wide open or at the temperature limit, as "base loaded" is often used for different purposes in power plants.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Tacoma Power	No	A text search of all three standards did not return the term "base loaded". Tacoma is not aware of an industry standard definition for the term "base loaded". If a unit is typically left at static output to meet base system load requirements it may likely still have droop as part of its governing system. As such, it would still be expected to respond to system frequency excursions.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Florida Municipal Power Agency	No	As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Also, if responsive control mode operation for		

Organization	Yes or No	Question 7 Comment
connected operations is established, model verification per the periodicity in Row 4 of the current draft of Attachment 1 would be required.		
PPL	No	We do not see in MOD-027-1 any language that defines baseloaded units as being verified and consequently exempts them from testing. It is true that a gas turbine running at the OEM-established baseload firing temperature is maxed-out and will therefore not exhibit any response to a frequency dip, but it is unclear what units are "always base-loaded." We also do not see any suitable definition of the term, "base loaded unit." The NERC Glossary defines "Base Load" as, "The minimum amount of electric power delivered or required over a given period at a constant rate;" but so-called baseloaded units may not run at a constant rate, instead often cycle between full output and minimum load on a daily basis.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
ACES Power Standards Collaborators	No	Conceptually, we agree with the concept of an exemption. However, it is not clear to us where this exemption is located within the standard and how it would even apply. Given the penetration of large amounts of wind and record low natural gas prices, many units that might traditionally be based load might actually operate below the maximum capabilities frequently. Our first question then, is what does it mean to be based loaded and what units qualify? Second, what does an exemption mean? Does it mean that a frequency excursion does not have to be observed or an on-line speed governor reference change test or partial load rejection test does not have to be performed? If so, does a model still have to be provided? Any exemption must be explicitly clear to avoid ambiguity and to ensure that auditors will interpret the exemption in the same manner as registered entities.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Consolidated Edison Co. of NY, Inc.	No	The term "base loaded" is not defined in MOD-027.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Luminant Energy Company LLC	No	Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. **We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.** Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and include the exemption that excludes units that are base loaded. **The GVSDT agrees that Net Capacity Factor is appropriate and has incorporated that into the standard. Please see responses to similar questions to yours in this**

Organization	Yes or No	Question 7 Comment
		document dealing with base-load units. The GVSDT thanks you for your comment. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3). **Nuclear units are not exempt from the requirements in this Standard. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Dynegy	No	We don't understand the question. The two sentences seem to contradict themselves.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Ingleside Cogeneration LP	No	Although Ingleside Cogeneration LP agrees with the concept that a base load unit does not need to be verified, it is not sufficient to capture this exception only in Attachment 1 of MOD-027-1. Similar to the exclusions for units with very low capacity factors, the Applicability section must also clearly identify that base loaded units are not subject to MOD-027-1.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. This is not an exemption, so a change in the applicability section would be inappropriate.		
Public Service Enterprise Group (PSEG)	No	We agree with exempting base load units; however, the term "base load" or "base loaded" is not referenced in the standard. We could not find the exemption or a definition of "base load" in MOD-027-1.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Luminant Power	No	Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and specifically include the exemption that excludes units that are base loaded in the standard. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3).
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner.		

Organization	Yes or No	Question 7 Comment
Units which respond to over-frequency would need to have verification performed. **Per your and other industry comments, the SDT is specifying the use of Net Capacity Factor for the capacity factor calculation.** **Nuclear units are not exempted, but there is a row in the Attachment 1 that accounts for units that do not respond to frequency excursions.**		
Manitoba Hydro	No	See comment (2) in Question 8.
Response: The GVSDT thanks you for your comment. Our response will show up under Question 8.		
Wisconsin Electric Power Company	No	We agree with the concept of an exemption for units that are running most of the time. It is not at all clear where this exemption exists in the standard. Does this mean that a "base-load unit" never requires a model verification? If not, it is unclear what purpose this exemption serves.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Ameren	No	We are in agreement with the exemption in the statement, but unclear where it is provided in either the Requirements or Attachment 1. Please clarify how this option is allowed.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize		

Organization	Yes or No	Question 7 Comment
for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
ISO New England Inc.	No	Base loaded units could provide governor response for over-frequency events and should have verified models for this event.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
American Electric Power	No	We can find no mention of "base load units" in Attachment 1 or anywhere in the standard, so it is not clear that those units have indeed been exempted. There needs to be more explicit references and/or parameters with respect to the meaning of "base load units" in the body of the standard rather than an implied reference in the attachment. We don't know what the SDT believes is a "base load unit"; therefore, we cannot support an exemption.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Exelon	No	As stated in the previous comments from Exelon as documented in the Consideration of Comments on Generator Verification (MOD-027-1) - Project 2007-09 dated

Organization	Yes or No	Question 7 Comment
		2/23/12 (pp 46-47) the proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that “Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units...”. The response from the SDT on Exelon's comment was to add an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in control mode, except during normal start up and shut down, that would result in a turbine/governor, and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT further stated that they believe this modification to MOD-027-1 will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode. While Exelon appreciates and agrees with the addition to Attachment 1 (the Periodicity Table) as stated above, Exelon is concerned that this exclusion may not be interpreted uniformly across the Regions or by auditors and therefore suggests that the exclusion be explicit to exempt "base loaded nuclear units that do not respond to grid frequency deviations" and that the exclusion be added to the Applicability section of MOD 027-1. Note that there is no definition in the NERC Glossary of Terms of a "base loaded unit" and in a deregulated environment the term "base loaded unit" is problematic. Therefore Exelon strongly suggests that nuclear units should be explicitly excluded due to the reasons provided above. Exelon suggests addition of the following to the Applicability Section. 4.2.4 Individual base loaded nuclear generating units that do not respond to frequency deviations are exempt from the verification requirements of Standard MOD-027-11 R.2 1Base Load nuclear generating units that do not respond to grid frequency deviations are required to document circumstance for exemption in accordance with Attachment

Organization	Yes or No	Question 7 Comment
		1Exelon suggests addition of the following to the Attachment: The existing SDT proposed exclusion is as follows:"New or existing applicable unit is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)"Exelon suggests revising as follows: New or existing applicable unit is considered a Base Load nuclear generating unit that is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. **Nuclear units are not exempted, but there is a row in the Attachment 1 that accounts for units that do not respond to frequency excursions.**		
Texas Reliability Entity	No	Only base-loaded units that are nuclear units should be exempted.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. **Nuclear units are not exempted, but there is a row in the Attachment 1 that accounts for units that do not respond to frequency**		

Organization	Yes or No	Question 7 Comment
excursions.		
Entergy Services, Inc	No	Entergy sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
City of Vero	No	As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Also, if responsive control mode operation for connected operations is established, model verification per the periodicity in Row 4 of the current draft of Attachment 1 would be required.		
Duke Energy	No	Where in this standard is this exemption for base load units? Regardless, base load units do exhibit some response, and the data collection is not difficult to accomplish.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Georgia Transmission Corporation	No	This is a MOD 25 question
Response: The GVSDT thanks you for your comment. The question was meant for MOD-027.		
Dominion- NERC Compliance Policy	Yes	Dominion agrees that base loaded units should be exempted; however, that exemption is not clearly articulated in the standard. Dominion recommends that a base load exemption statement be added to the "Applicability" section of the standard.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Southern Company	Yes	We agree that base load units should not be required to respond to demonstrate they will respond for underfrequency events and this should be reflected the transmission models.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize		

Organization	Yes or No	Question 7 Comment
for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
American Transmission Company, LLC	Yes	ATC agrees with the exception for base load units, however, recommends adding text that explicitly highlights that the second to last item in "Event Triggering Verification" column refers to base loaded units such as, "New or existing base loaded units that are normally not responsive to a frequency excursion event".
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Public Utility District No. 1 of Clark County	Yes	I agree with the concept but have been unable to find where in the proposed standard such an exemption is described. My Utility has one generator that is always operated as a baseloaded unit.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Southwest Power Pool Standards Development Team	Yes	

Organization	Yes or No	Question 7 Comment
Puget Sound Energy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
ExxonMobil Research and Engineering	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Los Angeles Department of Water and Power	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 7 Comment
AECI	Yes	
American Wind Energy Association	Yes	
Seattle City Light	Yes	
Kansas City Power & Light	Yes	
SERC Generation Subcommittee		No comment
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.
Cowlitz County PUD		Cowlitz could not find any mention of “base loaded unit” in MOD-027-1.
Indiana Municipal Power Agency		No comment

8. Do you have any other comment, not expressed in questions above, for the GV SDT regarding MOD-027-2?

Summary Consideration: Stakeholders provide many suggestions for revisions to the standard. The following revisions were made by the GVSDT:

1) **A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
2) **For clarity and ease of reading, moved a paragraph within R3 to the end of the requirement.**
3) **Changed "facility" to "unit" in Measures 2 and 4 to match the terminology in the requirements. Also, other minor clarifications and edits made in the Measures.**
4) **Changed "and" to "or" everywhere the phrase "and active power/frequency control functions" appears.**
5) **Revised R2 to remove "within 365 calendar days ......"**
6) **Revised R2.1.1 to specify "unit's MW model response".**
7) **Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the expert performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.**
8) **Revised Attachment 1 extensively for clarity, including removing specificity regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.**
9) **Revised the Effective Dates, and subsequently the Implementation Plan, to mirror the Effective Dates in the current draft of MOD-026 (verification of Excitation Control Systems).**
10) **Removed an extra word "that" (just before the word accurately) in the Purpose statement.**
11) **The qualifier "directly connected" was applied at the top level of the Facilities section (A4.2) to emphasize direct connection to the BES.**
12) **The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.**
13) **The SDT revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability**

section to a row (Row 8) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 5)

Organization	Yes or No	Question 8 Comment
Balancing Authority of Northern California	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Balancing Authority of Northern California	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
Consolidated Edison Co. of New York	Affirmative	See Individual Company and NPCC group comments
Response: The GVSDT thanks you for your comment. Please refer to responses to Individual Company and NPCC group		

Organization	Yes or No	Question 8 Comment
comments.		
Pacific Gas and Electric Company	Affirmative	see WECC comments
Response: The GVSDT thanks you for your comment. Please refer to responses to WECC comments.		
Independent Electricity System Operator	Negative	1. In our previous comments, we raised a concern that Parts 5.1 to 5.3 in Requirement R5 may not be achievable despite good faith effort by the responsible entities to verify equipment model. Specifically, R5.3 stipulates that a disturbance simulation resulting in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping be used to demonstrate that the model is usable. This may not be achievable, especially if such devices are new for which there are no previous simulations to benchmark with. In our previous comments, we disagreed with the condition that the simulations must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping can be affected by a number of other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to the system exhibiting positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, or a no-disturbance simulation always results in negligible transients. We suggested the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable. The SDT did not make any changes. From its response, it appears that the SDT didn’t quite understand the technical basis of our concerns.

Organization	Yes or No	Question 8 Comment
		Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance **The models can be tested, as described in Part 5.1 to Part 5.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.** **The SDT wants to reiterate that model usability is a different issue than model validation. The objective here is to harmonize the validated models being provided by the Generation Owners with the actual requirements from the Transmission Planners and, ultimately, the ISO and all end-users of these models. Some regions have already established lists of approved or acceptable models.** **Requirement R5, Parts 5.1 to5.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.** 2. The change in the Applicability Section 4.2.1 from a 100kV threshold (for generators having to meet the requirements) to an MVA based threshold is a step in the right direction. However, there does not appear to be any technical justification for two of the proposed criteria, namely, 100 MVA for individual units directly connected to the bulk power system and generating plant with a total of 100 MVA connecting to the bulk power system at a common bus. There is no rationale given

Organization	Yes or No	Question 8 Comment
		for assigning a 100 MVA for individual units as opposed to a 20 MVA, which is the registration criteria, and for assigning 100 MVA for plant aggregate capability as opposed to the 75 MVA that is applicable to almost all other standards on generator model verification (e.g. MOD-026), relay loadability, protection maintenance and testing, etc. Similarly, there is no rationale provided for Applicability Section 4.2.2 first bullet, and Section 4.2.3 first bullet for WECC and ERCOT, respectively. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.**
Response: Thank you for your comment. Please see responses above.		
Seminole Electric Cooperative, Inc.	Negative	a) 4.2: BPS is not a NERC defined Term in the NERC Glossary of Terms **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** b) Note 2 refers to "Applicable generating units do not include startup or standby units not normally connected to the grid." How are startup and standby units defined? **Turbine/Governor and Load Control or Active Power/Frequency Control models are less important for a startup or standby emergency power source because these units are not typically modeled in planning studies. When needed, these units are started in isolated or islanded mode to power black start unit auxiliaries and are not configured to control grid frequency. The SDT has decided to remove this footnote as industry comments show that it has caused confusion.**
Response: Thank you for your comment. Please see responses above.		

Organization	Yes or No	Question 8 Comment
Kissimmee Utility Authority	Negative	Applicability could be simplified considerably to: o Generating Facility unit > 100 MVA gross nameplate (75 WECC, 50 ERCOT o Generating Facility plant/farm in aggregate > 100 MVA gross nameplate. (75 WECC and ERCOT) **The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.** Bullet 2.2 seems to require aggregate models for plants where units are < 20 MW. Should individual models be an option, or only aggregate? **The SDT has refined section 4.2.2 of the Facilities section under Applicability to clarify the use of individual and aggregate models for plants. This clarification is also made in Part 2.1, and Part 2.2 has been deleted.** Do we have the appropriate equipment installed to measure excursions? Will we know when an excursion exceeds the frequency excursion criteria without installing equipment? **The GVSDT is closely following and coordinating with the Frequency Response Standard Drafting Team. It is hoped that the FRSDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, this is still in the conceptual phase and no processes are yet in place to identify and capture frequency excursions that meet the criteria. If a staged test is not performed, and monitoring equipment or access to SCADA data is not already in place, then each entity would have to install monitoring and recording equipment on its system in order to verify the governor responses to a system frequency excursion. It should be noted that the sampling rate required of the monitoring equipment for governor model verification is not high (one sample per 2 seconds – some entities have used even slower sampling rates) If the**

Organization	Yes or No	Question 8 Comment
		recording equipment installed included frequency threshold triggers, these triggers could be utilized to capture and identify appropriate frequency excursions, which would negate dependence on any processes defined by the FRSDT. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more. The "OR" statements are ambiguous in the table of Attachment 1: o On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line. Finally, the model representing the new equipment cannot be verified until the new equipment is installed. Also, this standard addresses model verification, not the submittal of preliminary design models.** o On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? ? **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line**

Organization	Yes or No	Question 8 Comment
		o On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line** o etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? Recommend numbering the rows sow that the Row references are clear as to whether the heading row is included in the count. **The reference to 365 days was removed. The GVSDT revised Attachment 1 to remove specificity regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.**
Response: Thank you for your comment. Please see responses above.		
Beaches Energy Services	Negative	MOD-027 Applicability could be simplified considerably to: Generating Facility unit > 100 MVA gross nameplate (75 WECC, 50 ERCOT Generating Facility plant/farm in aggregate > 100 MVA gross nameplate. (75 WECC and ERCOT) **Thank you for your comment. The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.** Bullet 2.2 seems to require aggregate models for plants where units are < 20 MW.

Organization	Yes or No	Question 8 Comment
		Should individual models be an option, or only aggregate? **Thanks you for your comment. The SDT has refined section 4.2.2 of the Facilities section under Applicability to clarify the use of individual and aggregate models for plants. This clarification is also made in Part 2.1, and Part 2.2 has been deleted.** Do we have the appropriate equipment installed to measure excursions? Will we know when an excursion exceeds the frequency excursion criteria without installing equipment? **The GVSDT is closely following and coordinating with the Frequency Response Standard Drafting Team. It is hoped that the FRSDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, this is still in the conceptual phase and no processes are yet in place to identify and capture frequency excursions that meet the criteria. If a staged test is not performed, and monitoring equipment or access to SCADA data is not already in place, then each entity would have to install monitoring and recording equipment on its system in order to verify the governor responses to a system frequency excursion. It should be noted that the sampling rate required of the monitoring equipment for governor model verification is not high (one sample per 2 seconds – some entities have used even slower sampling rates) If the recording equipment installed included frequency threshold triggers, these triggers could be utilized to capture and identify appropriate frequency excursions, which would negate dependence on any processes defined by the FRSDT. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more.** The "OR" statements are ambiguous in the table of Attachment 1: On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the

Organization	Yes or No	Question 8 Comment
		Criteria 1 threshold. Is that the correct interpretation? On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? Recommend numbering the rows sow that the Row references are clear as to whether the heading row is included in the count. **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.**
Response: Thank you for your comment. Please see responses above.		
Northern Indiana Public Service Co.	Negative	Confusion since the Bulk Power System (BPS) and Bulk Electric System (BES) are both mentioned within these standards; they are not the same
Response: Thank you for your comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
Great River Energy	Negative	Great River Energy agrees with the comments of the MRO NSRF and ACES Power Marketing.
Response: Thank you. Please see response to comments of the MRO NSRF and ACES Power Marketing		

Organization	Yes or No	Question 8 Comment
Old Dominion Electric Coop.	Negative	I am sure that not all GOs will be able to supply the mode data requested in teh format requested by the TP since some units are old and this data does not exist for them. Add an exemption process for those generators that cannot provide their data.
Response: The GVSDT thanks you for your comment. Generic models exist that should adequately model any governor type. Once verification is completed and the data applied to the generic model, the model should be useful for system planning. Therefore, the GVSDT does not believe that an exemption should be granted solely due to lack of documentation.		
Pacific Gas and Electric Company	Negative	MOD-027-1 paragraph 4.2.2 of applicability section is unclear. This paragraph and sub-bullets seem to have the intent to clarify which generating units must be modeled. However, The second bullet includes generating plant or facility consisting of one or more units connected to the bulk power system at a common bus with total generation greater than 75 MVA. The sub-bullets then define individual generating unit greater than 20 MVA and generating plant or facility comprised of individual generating units less than 20 MVA. At face value it would seem to include both units greater than 20 MVA and less than 20 MVA. If the intent is to include individual models for units greater than 20 MVA and an aggregate model for the sum of all units less that 20 MVA, that should be clearly identified. However, it does leave the reader wondering what to do with units that are exactly 20 MVA.
Response: Thank you for your comment. Based on your comment, the SDT has refined section 4.2.2 of the standard applicability to add additional clarity.		
JEA	Negative	MOD027-1: Believe that requiring verification for facilities with a capacity factor of only 5% is too stringent. Provide some type of justification for this value or increase. A unit with only a 5% capacity factor will usually not be part of the BES if an event

Organization	Yes or No	Question 8 Comment
		occurs and so we need to balance the cost verses the probability of impact.
Thank you for your comment. The SDT believes it is not necessary to require all units in the compliance registry to have models unit capacity factor of 5% equates to greater than 400 hours of annual unit run time. The 5% capacity factor exemption was selected a balance between the cost and benefits. **The SDT revised the draft standard to reference the net capacity factor calculation in f of the GADS Data Reporting Instructions. Also, the SDT moved the details of the capacity factor exemption concept form a footnote icability section to a row (Row 8) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table luded the "equivalent" unit concept (Row 5).**		
Omaha Public Power District	Negative	OPPD supports MRO NSRF comments
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Dairyland Power Coop.	Negative	Please see comments submitted by MRO NSRF.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Muscatine Power & Water	Negative	Please see the comments submitted by NSRS for Project 2007-09 Generator Verification.
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please refer to our responses under ACES Power Marketing.		

Organization	Yes or No	Question 8 Comment
Essential Power, LLC	Negative	R1 and parts of R2 are, in effect, duplicative of requirements in other Standards. The requirement for the GO should be to simply provide the specific data, in the format requested, as requested by the TP. **Requirements R1 and R2 are not duplicative requirements in other Standards. The GVSDT believes that all of the Requirements are necessary to ensure successful model verification. Requirements R1, R2, and R5 are always required, but Requirements R3 and R4 are anticipated to be rarely used for model verification activities that are not expected to occur frequently.** In regards to the facilities to which this Standard is applicable, the term 'bulk power system' used in section 4.2 is ambiguous and is not defined in the current, approved version of the NERC Glossary of Terms. The term should be changed to 'Bulk Electric System', as defined in the Glossary. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
Response: Thank you for your comments. Please see responses above.		
Lincoln Electric System	Negative	Refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Response: The GVSDT thanks you for your comment.		
Brazos Electric Power Cooperative, Inc.	Negative	See ACES Power Marketing comments.
Response: The GVSDT thanks you for your comment. Please refer to our responses under ACES Power Marketing.		

Organization	Yes or No	Question 8 Comment
Luminant Energy	Negative	See comments submitted by Luminant Energy. VOTE NO based on a comparison of R2 and corresponding VSL. It is unclear how the time frames are to be aligned.
Response: The GVSDT thanks you for your comment. The requirement is for the Generator Owner to provide a verified model within certain time frames per Attachment 1. If the Generator Owner fails to meet the time requirement, the VSL will be used to determine where the violation falls within the penalty matrix. Each VSL is written such that successive VSLs are incremented by 30 days for instances of the model being provided late.		
Midwest ISO, Inc.	Negative	See comments submitted by MRO NSRF.
Response: The GVSDT thanks you for your comment.		
New Brunswick System Operator	Negative	See comments submitted by NPCC Reliability Standards committee.
Response: The GVSDT thanks you for your comment.		
Florida Municipal Power Pool	Negative	See FMPA comments
Lakeland Electric	Negative	See FMPA comments.
Response: The GVSDT thanks you for your comment.		
Central Electric Power Cooperative	Negative	see Matt Pacobit's comments from AECI
N.W. Electric Power Cooperative, Inc.	Negative	see Matt Pacobit's comments from AECI

Organization	Yes or No	Question 8 Comment
KAMO Electric Cooperative	Negative	See Matt Pacobit's comments from AECI
Northeast Missouri Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
M & A Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI.
Sho-Me Power Electric Cooperative	Negative	See Matt Pacobit's comments from AECI.
Response: The GVSDT thanks you for your comment.		
U.S. Army Corps of Engineers	Negative	See MRO-NSRF comments.
Response: The GVSDT thanks you for your comment.		
New York Power Authority	Negative	See NPCC submitted comments
Response: The GVSDT thanks you for your comment.		
Snohomish County PUD No. 1	Negative	SNPD supports changing the WECC generator and generator unit thresholds to be consistent with the 100 MVA thresholds referenced in the Eastern and Quebec Interconnections applicability sections. **The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.** SNPD also supports clarifying the language in MOD 027-1. As currently written the standards do not clearly indicate the testing that is required for plants with an

Organization	Yes or No	Question 8 Comment
		aggregate generation level greater than 75MVA and comprised of multiple units that are both greater than 20 MVA and less than 20 MVA. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** SNPD suggest changing the Bulk-Power System references to Bulk Electric System ("BES") to be consistent with most of the other NERC Reliability Standards and the title of the published Reliability Standards "Reliability Standards for the Bulk Electric Systems of North America. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Clark Public Utilities	Negative	The effective date section of the standard provides a confusing implementation for a utility that has only one generator. Please address this issue. I suggest that you add the following to end of section 5.1.5, "This section applies to a Generator Owner and Transmission Owner having only one applicable facility." **The intent is that at least 30% of the connected MVA must be compliant by the end of 4 years. Thus an entity with only one generator will need to complete the validation within first 4 years.** Also, the comment questionnaire indicated there is supposed to be an exemption for baseloaded generators. I cannot find such an exemption in the proposed standard. **The SDT inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that**

Organization	Yes or No	Question 8 Comment
		effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.
Response : Thank you for your comments. Please see responses above.		
Detroit Edison Company	Negative	The implementation plan is shorter than MOD-26, seems to me verifications of both these standards could be accomplished concurrently. Therefore the implementation schedules for MOD 26 & 27 should match.
Response: Thank you for your comments. The GVSDT has made the suggested modification.		
Tucson Electric Power Co.	Negative	The purpose statement appears to have an unnecessary word “that” immediately preceding the word accurately. If the intent of the sub-sub-bullets in the applicability sections is intended to require that individual units greater than 20 MVA at generating plants greater than the identified Interconnection minimum be represented individually, while units less than 20 MVA at generating plants greater than the identified Interconnection minimum be represented as an equivalent. Do not believe that the intent is clearly reflected in the words in the sub-sub bullets. The sub-sub bullets in the applicability section use both “consisting of” (4.2.1) and “comprised of” (4.2.3) and use “consisting comprised of” in 4.2.2. The language should be consistent and the grammatical error in 4.2.2 should be corrected.
Response: The GVSDT thanks you for your comment. The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.		
Tucson Electric Power Co.	Negative	The Severe VSL for R2 includes providing required models more than 90 days late and also includes not providing models. It is not necessary to include the part about not providing models. If models are never provided, they are more than 90 days late. The VSLs for R5 should use “less than or equal to” rather than just “less than” in the

Organization	Yes or No	Question 8 Comment
		sections identifying how many days late the written response was provided.
Response: The GVSDT thanks you for your comment. The GVSDT agrees with your comments and has adopted them into the standard.		
Clark Public Utilities	Negative	The standard needs to recognize there are generator owners and transmission owners that have only a few applicable facilities and the percentage fulfillment requirement in the effective date section will be a cause of confusion. Please fix it now before the standard is approved.
Response: Thank you for your comments. The GVSDT has revised this section to make it clearer. The percent values are minimum values. An entity can always choose, or may have to implement due to the fact that the number of units in their fleet is small, a higher percentage value to remain compliant.		
Sunflower Electric Power Corporation, North Carolina Electric Membership Corp.	Negative	We do not believe the VRF Requirement R5 should have a Medium VRF. It is an administrative requirement that is focused on notifying the Generator Owner as to the suitability of the model they provided. **From the VRF Guideline, a Medium Risk Requirement is:** **"A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under**

Organization	Yes or No	Question 8 Comment
		emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition." **Requirement R5 is linked directly to Requirement R2 and is a confirmation that a verified model is useable to plan the BES. If a verified model is provided by the Generator Owner, the Transmission Planner must determine whether or not the model is useable. If this step in the process is missing, then the validity and usefulness of the model is uncertain. Using uncertain models can lead to the BES being improperly planned and could "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system."** **Therefore, Requirement R5 is assigned a Medium VRF.** Additionally, conforming changes to the VSLs are required based on changes recommended to the standards in the formal comments submitted by ACES Power Marketing. **Please see response to ACES Power Marketing comments.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Southern Company	Yes	1) Applicability 4.2.1, 4.2.2, and 4.2.3 use the term "bulk power system" and should be "Bulk Electric System (BES)". We believe the >100kV criteria language should be retained. We believe the exemption for units that, by design, do not respond to frequency should be clearly stated in the Applicability section. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The units that do not respond to both under and over frequency excursions by design are compliant by informing**

Organization	Yes or No	Question 8 Comment
		the Transmission Planner. The revised periodicity table (Attachment 1) provides for that. All one has to do is submit a statement to that effect to the Transmission Planner. It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. We believe this to be true even when it is part of a plant or Facility with an aggregate gross rating >100MVA. NERC is supposed to focus on creating standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. For plants and Facilities with an aggregate rating >100 MVA we recommend deletion of the two sub-bullets in 4.2.1, 4.2.2, and 4.2.3. In conjunction with this change, we recommend that R2, sub-part 2.2 be revised to state, "For plants or Facilities with gross aggregate rating greater than the specified thresholds in 4.2.1, 4.2.2, or 4.2.3, perform verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts.** **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** 2) The Eastern Interconnection frequency excursion criteria of greater than or

Organization	Yes or No	Question 8 Comment
		equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don't provide data that is nearly as meaningful as excursions at 0.06 or 0.07." **The standard provides the minimum deviation to use, and certainly a larger deviation would be better if available. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more.** 3) Measure M2 uses the term applicable "Facilities" while R2 uses the term applicable "units". Either is acceptable to us, but the requirement and measure should use the same terminology. **The GVSDT is using the term "facility" interchangeably with "unit" in this standard. However, for clarity, the term "unit" will be used in the measure to match the requirement terminology.** 5) The purpose statement is written in a convoluted form - a more straightforward presentation could be: "To verify the models used in dynamic simulations accurately represent the generating unit real power response to system frequency variations". **The GVSDT attempted to write the purpose statement to apply to various technologies, and most of the industry found it acceptable. We considered your suggestion but did not revise the purpose statement.** 6) In Requirement R3, the paragraph above the three bullets would be more appropriate if moved below the three bullets.

Organization	Yes or No	Question 8 Comment
		Your suggestion has been incorporated. 7) Consider modifying the implementation plan to allow years for 10%, 5 years for 25%, 7 years for 50%, 9 years for 75%, and 11 years for 100% model verification due to the fact that a learning curve is involved and many entities have large numbers of units. **The applicability date requirements have been revised to match MOD-026 standard where a similar learning curve is involved.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
PacifiCorp	Yes	1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of 4.2 - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for the first bullet under section 4.2.2): "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made throughout section 4.2 where applicable. **The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The GVSDT has considered your suggestion and hopes that the use of the NERC defined term "Bulk Electric System" will make the applicability clearer. Also, the "directly connected" qualifier has been inserted at the top level of the Facilities section (A4.2).**

Organization	Yes or No	Question 8 Comment
		2. PacifiCorp believes that the sub-bullets of the second bullet under Section 4.2.2 of the "Applicability" section (and elsewhere, as applicable) introduce confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing sub-bullets under the second bullet of section 4.2.2: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows:"For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5." **The SDT moved the language that was in Part 2.2 to Part 2.1, and modified the language to make it clear that the use of individual or aggregate models for units less than 20 MVA (gross nameplate capability) is left to the discretion of the expert performing the model verification.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Ameren		(1) Footnote 4: “...validated from on load data...” For clarification, please consider that this be changed to read “...validated from on-line unit data...”.

Organization	Yes or No	Question 8 Comment
		The text has been updated and your suggestion has been taken into consideration. (2) Regarding the title of Attachment 1 "Turbine/Governor and Load Control and Active Power/Frequency Control Model Periodicity" - should the 'and' before 'Active Power/Frequency Control' be changed to an 'or' to be consistent with the title of the draft Standard? Similarly, the phrase "turbine/governor and load control and active power/frequency control" appears in several places in the VSL table. Should the 'and' before 'active power/frequency control" be changed to 'or' in these instances for consistency? **The GVSDT has attempted to improve the clarity of Attachment 1. The GVSDT agrees with your comment and has revised the standard to "or active power/frequency control functions".** (3) Violation Severity Levels - R5 Moderate: There is conflict here because failure to respond within 150 days automatically puts one in the High category. **The GVSTD agrees with your comment and has revised the standard accordingly.** (4) There is a concern that different effective dates between the MOD-26 and MOD-27 standards will be burdensome for the Transmission Planner to track and analyze model updates. The Transmission Planner would prefer to receive the exciter and governor models updates for a specific unit at the same time. **The effective date requirements have been revised to match MOD-26 standard.** (5) Replace "Bulk Power System" with "Bulk Electric System" In the Applicability section, items 4.2.1, 4.2.2, and 4.2.3. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** (6) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website. **The suggestion to provide technical documents on the NERC website is a good one,**

Organization	Yes or No	Question 8 Comment
		but because of copyright laws and the burden of maintaining the latest versions of the documents by NERC staff, the SDT does not believe this is feasible. (7) R2 and R2.1 require each GO to provide for each generator a "...verified turbine/governor and load control...model..." The GVSDT should provide guidance on how to quantitatively determine when a model is verified for each unit. **Based on a review of the Field Test results and experience of the SDT members, the SDT recognized that it was not desirable to develop a dynamic model verification Standard like a technical procedure manual. Such a strategy would fail as there is a wide range of equipment that will need to be verified. Thus, the SDT drafted a Standard that concentrates on "stating what is required" but without "stating how to accomplish what is required" so that the details can be managed by the modeling verification expert.**
Response: The GVSDT thanks you for the comments.		
Exelon		1) Exelon requests that the Implementation Plan for MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions," add a section to provide guidance on the applicability of Base Loaded nuclear generating units that do not respond to frequency excursion events as explained above. In addition to the exemption criteria, more guidance should be provided on the required "document circumstance with a written statement." **Nuclear units are not exempt from the requirements in this Standard.** **We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.** 2) MOD-027-1 R5 states that the Transmission Planner is to notify the Generator Owner within 90 calendar days whether the model is "useable" (i.e., meets the criteria specified in Parts 5.1 through 5.3). The usability of the model should be that

Organization	Yes or No	Question 8 Comment
		it mimics the generating unit governor regardless of whether the governor/model challenges transmission operating criteria. The requirement as written implies that a Transmission Planner could challenge the governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09 (as stated in the SAR) which is "[t]o ensure that generator models accurately reflect the generator's capabilities and operating characteristics." **Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance** **The models can be tested, as described in Part 5.1 to Part 5.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.** **The SDT wants to reiterate that model usability is a different issue than model validation. The objective here is to harmonize the validated models being provided by the Generation Owners with the actual requirements from the Transmission Planners and, ultimately, the ISO and all end-users of these models. Some regions have already established lists of approved or acceptable models.** **Requirement R5, Parts 5.1 to 5.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.** 3) Please clarify what is intended by an "applicable facility" with respect to

Organization	Yes or No	Question 8 Comment
		implementation. Is it the intent that the total population generating units that meet the characteristics in Requirements 4.2.1, 4.2.2 and 4.2.3 start as being "applicable units" for the purposes of implementation and then during the staggered implementation, each individual unit is to be evaluated for verification requirements?. For example, if a Generator Owner had ten units (five of which are nuclear units) each greater than 100 MVA and therefore all meet criteria of 4.2.1 then those ten units are in the scope of MOD-027-1 for implementation. This is regardless of any verification requirements that may then exempt them from verification per Attachment 1? **Your understanding of the applicability is correct that all units that meet the applicability threshold in sections 4.2.1, 4.2.2, and 4.2.3 are subject to model validation requirements. Also exemption guideline for applicable units is outlined in the Attachment 1.** 4) MOD-027-1 R1 is inappropriately prescriptive to Generator Owners (GOs). The Transmission Planner (TP) should merely ask for modeling parameters from a GO and not provide instructions on how to obtain acceptable models used in TP software. GOs may not own such software. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the model response matches the**

Organization	Yes or No	Question 8 Comment
		response from a recorded frequency excursion (or staged test allowed per Requirement R2). This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits 5) MOD-027-1 R2 is unclear as to the intended obligations. The sub-bullets in 2.1 should clearly state that following one or two of the sub-bullets are acceptable. Requiring all sub-bullets is too prescriptive and problematic. In the case of 2.1.1, fossil generating units are not likely to have the equipment necessary to demonstrate compliance. **The SDT believes that all of the applicable sub Parts in Part 2.1 are necessary to accomplish model verification. The GVSDT believes that the verification of the turbine/speed governor models can be accomplished with records containing frequency and power output, with ideal sampling rates of 1 second or faster. Some entities have verified these models using sampling rates of 4, even 6 seconds. Some plants might have such recording capability in their turbine (digital) controllers or their plant SCADA system, or obtain the data from their TOP scada system. If none of these options apply to a particular unit, a relatively inexpensive recorder with a relatively slow sampling rate (a sample every 1 – 4 seconds) to recorder the unit's MW response to frequency excursions may be required.** 6) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). **The GVSDT has taken your suggestion into account and replaced the term "bulk power system" with the NERC defined term "Bulk Electric System" without reference to registry criteria in the applicability section.**

Organization	Yes or No	Question 8 Comment
		7) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted. **The GVSDT is using the NERC Standard Template which contains the language that you have concerns with. This language was provided to the drafting team for inclusion in the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Texas Reliability Entity		1)Applicability: a. Section 4.2: Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements, whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection. The applicable Facility requirements should be the same for each Standard in this Project! **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The applicable facility requirements and effective dates are now consistent in MOD-026 and MOD-027.** b. Section 4.2: We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. **Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. This standard has been revised to specify the "net capacity factor" is to be used.**

Organization	Yes or No	Question 8 Comment
		c. The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an "applicable unit", then wait until a frequency excursion occurs to measure performance, then has 365 days to send the model data to the Transmission Planner. **Based upon your comments and others, we simplified Attachment 1. Now the Standard requires that the owner transmit the verified model and documentation and data to the Transmission Planner within 365 days after commissioning a new unit or making major equipment modifications.** 2)Effective Dates: a. Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correct model errors that may lead to (or have led to) improper planning of the system based on the current model results. **The standard applies to each individual unit and inaccuracies in model data of an individual unit have minimum impact on the reliability. There are thousands of units involved and there will be a learning period. Based upon the overwhelming positive response, the GVSDT thinks the 10 year implementation period is a reasonable compromise.** b. For establishment of initial verification period, the MOD-027 Attachment 1 "OR" phrase is inconsistent with the timeframes to be compliant per the effective dates (e.g. If a unit records a response on the "Standard Implementation Effective Date" and then has 365 days to send the data, how can it meet the 25% compliance requirements on the first day of the first calendar quarter three years following regulatory approval?) What is the "Standard Implementation Effective Date". **The GVSDT thanks you for your comment. The standard effective date is defined in**

Organization	Yes or No	Question 8 Comment
		section 5. We have revised Attachment 1 to attempt to clarify and simplify the requirement. The periodicity no longer references how the test is completed, and accordingly the effective dates were revised to match MOD-026. c. The SDT should consider moving the Consideration for Early Compliance criteria from Attachment 1 into the Effective Dates section. **The SDT has reformatted Attachment 1 for improved clarity. The consideration for early compliance could be included in section 5, "Effective Date", but we believe the flow of the standard is best if the early compliance information appears in Attachment 1 with the other clarifying criteria.** 3) R3: The inclusion of "or a plan" extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Do the plants need to disconnect until "usable" data is provided? **The SDT drafted the standard recognizing the model verification requires expertise and calendar time – a reality that exists today in the process even in the absence of a standard. It is expected that all entities will strive to verify the model as quickly as practical. In the interim, the Transmission Planner will likely utilize a conservative model that can be run in their software or continue using the models currently available. Also, the requirements from MOD-012 still apply, so it is expected that models are available, even though they might not be considered verified models, per the requirements in this Standard.** 4) R4: The inclusion of "or plans" extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Ddo the plants need to disconnect until "usable" data is provided? **The SDT drafted the standard recognizing the model verification requires expertise and calendar time – a reality that exists today in the process even in the absence of a standard. It is expected that all entities will strive to verify the model as quickly**

Organization	Yes or No	Question 8 Comment
		as practical. In the interim, the Transmission Planner will likely utilize a conservative model that can be run in their software or continue using the models currently available. Also, the requirements from MOD-012 still apply, so it is expected that models are available, even though they might not be considered verified models, per the requirements in this Standard. 5) VSL R2: The Severe VSL language is different from the Lower, Moderate, and High VSL language regarding the models. Language should be consistent. **The GVSDT has removed the following text from the Requirement R2 Severe VSL section, "turbine/governor and load control and active power/frequency control", in order to provide consistency with the other R2 sections.** 6)The following comments relate to Attachment 1: a.R3: The timeframes are too long. If a GO has a unit that the TP had deemed not "usable" it has 90 days to produce a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response-then has another 365 days to send the data to the TP. What does the TP do in the interim? b.R4: The timeframes are too long. If a GO has a unit that undergoes changes to the "turbine/governor and load control and active power/frequency control system" it has 180 days to produce the model data OR a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response-then has another 365 days to send the data to the TP. More time would be needed if the TP took 90 days to verify the model data and possibly 90 more days by the GO to defend the model data, changes or verification plan (per R5 and R3). What does the TP do in the interim? c. Comment column: How do "Comments" get used in an audit? If there is a requirement to transmit information within a certain timeframe, that should be included in the "Verification Periodicity" column and not the "Comments" column. d. Criteria 4: If there are going to be references, give the references a number rather

Organization	Yes or No	Question 8 Comment
		than referring to "4th row in the following table". **We have simplified and revised Attachment 1 in an attempt to answer comments received. This standard does not address how the TP will model the equipment in the interim until the GO meets this standard. This is a model verification standard, MOD-012 addresses the requirement to provide model data. The GO needs time to verify model data.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Indiana Municipal Power Agency		1)In section 4.2. under Facilities, IMPA recommends changing bulk power system to Bulk Electric System. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)IMPA supports the use of average capacity factor in the Facilities section of the standard.
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
Alberta Electric System Operator		1. In section 4.2.2, the AESO considers the existing applicability for model validation to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time**

Organization	Yes or No	Question 8 Comment
		consuming verification efforts. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. **The current and previous drafts of the standard have proposed a 10 year periodicity. The vast majority of comments from industry from prior posting have been in favor of a 10 year periodicity.** 3. Requirement R4, as written it appears owners of generating units that plan to change out the governor are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change. **The standard is a model verification standard and thus does not include the provision of preliminary (design) data. However, the standard does not preclude the practice which can be implemented through contractual agreements.**
Response: Thank you for your comment. Please see responses above.		
Independent Electricity System Operator		1. In the Applicability Section, 4.2.1, we agree with the change from a 100kV threshold to an MVA based threshold. However, there does not appear to be any technical justification for the first two bullets, i.e. 100 MVA for individual units directly connected to the bulk power system and generating plant with a total of 100 MVA connecting to the bulk power system at a common bus. Why would the first bullet not be 20 MVA and the second bullet not 75 MVA to be consistent with the registration criteria and the thresholds for generators having to comply with MOD-026 and PRC-019? Similar comments on 4.2.2 first bullet, and 4.2.3 first bullet for WECC and ERCOT, respectively.

Organization	Yes or No	Question 8 Comment
		As discussed in the Comment Form with the first posting of the draft MOD-027 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the dynamic models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the turbine/speed governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine/speed governor models, the SDT is proposing to require verification of such models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. 2. We continue to disagree with Requirement R5 and it Parts R5.1 to R5.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate turbine/governor and Load control or active power/frequency control model, especially if such devices are new for which there are no previous simulations to benchmark with. Part 5.3 stipulates one of the criteria for deeming a model usable. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data

Organization	Yes or No	Question 8 Comment
		can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable. **Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance** **The models can be tested, as described in Part 5.1 to Part 5.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.** **The SDT wants to reiterate that model usability is a different issue than model validation. The objective here is to harmonize the validated models being provided by the Generation Owners with the actual requirements from the Transmission Planners and, ultimately, the ISO and all end-users of these models. Some regions have already established lists of approved or acceptable models.** **Requirement R5, Parts 5.1 to 5.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.** **Indeed, there is an underlying assumption that (barred some mal-function in the equipment, which would have to be addressed) all controllers in a power plant**

Organization	Yes or No	Question 8 Comment
		result in stable operation. Thus, a verified model is expected to show a similar, stable response. Therefore, it is not unreasonable to expect a stable, damped response from these simulation models. The GVSDT is not aware of any examples to the contrary.
Response: Thank you for your comment. Please see responses above.		
Wisconsin Electric Power Company		a. In Section 3 "Purpose", reference is made to Bulk Electric System (BES) reliability. Then, in Section 4.2, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** b. In Section 4.2 Applicability, Footnote 2, the reference to startup or standby units should have further detail since these terms are not defined by NERC, or simply remove this footnote. **Turbine/Governor and Load Control or Active Power/Frequency Control models are less important for a startup or standby emergency power source because these units are not typically modeled in planning studies. When needed, these units are started in isolated or islanded mode to power black start unit auxiliaries and are not configured to control grid frequency. However, based on industry comments, this footnote appears to have caused confusion thus the SDT has decided to remove it.** c. In Requirement R1, instead of the Transmission Planner (TP) providing "instructions" on how the Generator Owner (GO) can obtain necessary models and associated information, the standard should require the TP to simply "provide" the

Organization	Yes or No	Question 8 Comment
		model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. In addition, the TP should provide the OEM model data sheets or other data supporting the current in-use models in the dynamics database. **The software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** d. In R2.1.1, the GO is required to provide documentation comparing the turbine/governor model response to the recorded response for a frequency excursion while online, or a change in reference while online, or a partial load rejection test. Since the GO usually does not have the capability to run such dynamic studies, it is not clear how will it obtain the "model response" for comparing to the recorded response. When there is more collaboration between NERC, Generator Owners and OEM's on the methods for online governor verification (see Question 5 response above), only then should there be any requirement that the GO "provide the recorded response for a frequency excursion". As presently written, R2.1.1. can only be required of the TP. Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the data required in R2.1.1. This standard is too far ahead of the existing capabilities for verifying these controls. More work is needed, and it is strongly suggested to bring OEM's into the process to enable the development of a useful standard.

Organization	Yes or No	Question 8 Comment
		The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that model response matches the MW response from the applicable unit during an appropriate frequency excursion when the unit is in a mode in which it is expected to govern. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. Also, even though the GO would be responsible for the requirement from a compliance perspective, they could enter into an agreement with their Transmission Planner to perform a portion or all of the model verification activities. e. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the business need to develop these equivalent models like the TP does for system modeling. This requirement would demand resources in return for no increase in reliability. The requirement should allow the GO the ability to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate model. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section**

Organization	Yes or No	Question 8 Comment
		Applicability and Part 2.1 to provide added clarity. The new language will provide flexibility for generator owner to provide either individual or aggregate model for units rated less than 20 MVA. The standard does not preclude the Generator Owner and the Transmission Planner from working together. f. It is not clear how this standard relates to variable resources such as wind farm. It is suggested that these generating sources should be specifically excluded from the Applicability. **Some wind equipment have controls that can respond to a frequency excursion. For wind equipment that does not possess this capability, the SDT has included a row in Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency. For these units compliance with the Requirement is shown by maintaining documentation explaining the unit's operating limitations.**
Response: Thank you for your comments. Please see responses above.		
Duke Energy		o Applicability Section 4.2 Facilities - Need to specify "net" or "gross" capacity factor for the calculation. **The standard has been revised to specify "net capacity factor" throughout.** o R2, 2.2 - Insert the phrase "or individual unit" after the word "aggregate". **The SDT moved the language that was in Part 2.2 to Part 2.1, and modified the language to make it clear that the use of individual or aggregate models for units less than 20 MVA (gross nameplate capability) is left to the discretion of the expert performing the model verification.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Pepco Holdings Inc and Affiliates		Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of

Organization	Yes or No	Question 8 Comment
		this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition.
Response: Thank you for your comments. The GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.		
Transmission Access Policy		As stated with respect to MOD-025 in TAPS response to Question 2 above, the

Organization	Yes or No	Question 8 Comment
Study Group		Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of MOD-027 be revised as follows (note that we have suggested no changes to section 4.2.3 because TAPS has not investigated the relevant conditions in ERCOT): "For the purpose of this standard, the term 'applicable Facility' is considered, 'applicable units.' Units or plants with an average capacity factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following: 4.2.1 BES generating units/plants connected to the Eastern or Quebec Interconnections with the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 100 MVA (gross nameplate rating). 4.2.2 BES generating units/plants connected to the Western Interconnection with the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 75 MVA (gross nameplate rating). ...A generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator's restoration plan is not an applicable Facility for the purpose of this standard."
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The GVSDT has made modifications to the structure of Section 4 for clarity of intent. The standard would not be applicable to most black-start units by virtue of low capacity factor.		
Consolidated Edison Co. of NY, Inc.	Yes	Comments: o Con Edison strongly supports the intent and goal of MOD-027 and the SDT efforts to achieve more accurate system modeling. o Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity

Organization	Yes or No	Question 8 Comment
		factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. **The GVSDT believes that units with less than 5% capacity factor are much less likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. The GVSDT is also aware of the fact that the very low capacity factor units will not be available for testing while operating at peak times, and it will be very expensive to test them at other times. Thus, it was necessary to establish a threshold for the applicability of the Standard.** o Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the turbine/speed governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine/speed governor models, the SDT is proposing to require verification of turbine / governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric**

Organization	Yes or No	Question 8 Comment
		System", and we believe that this is consistent with the >100 kV requirement. o Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** o Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance. We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this the SDT's understanding? **Section 5.1 has been revised to make it clearer. The intent is that the entity with one unit will need to be compliant within the first four years of standard approval date.** o R2: we believe that there is linkage between the parenthetical "(within 365 calendar days from the date that the response was recorded)" and the reference in 2.2.1 "...unit's model response to the recorded response for either....", but this language is not clear. The SDT is encouraged to clarify what the term "response" in the parenthetical is referring to. **The text has been revised and hopefully addressed your concerns.** o R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. We recommend the following verbiage to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc) and any protection

Organization	Yes or No	Question 8 Comment
		system controls (i.e. emission control systems on combustion turbines, etc) [delete: effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that override the governor response (including blocked or nonfunctioning governors or modes of operation that limit] the frequency response if applicable. **The SDT considers the representation of outer loop controls, particularly MW control loops, as an important element to properly represent the response of the turbine/speed governor following frequency disturbances. Thus, item 2.1.5 was included focusing specifically in this kind of component or control. The inclusion of pressure limiters and/or emission control systems in the model is left to the technical expert verifying the model.** o R3: first bullet, term "usable" should be revised to "usable as defined in Requirement 5". Note that R5.1, 5.2 and 5.3 clearly define the criteria for "usable". o Section G References: delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard. **The text has been revised to indicate that usability is related to the Requirement R5.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
PPL		Comments; a. The comparison of actual and expected response in R2.1.1 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide also high-speed recordings of responses to grid-disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is clear that there any purpose to making GOs do so. **The SDT believes only one entity can be assigned responsible for model verification and that entity should be the Generator Owner – a concept that was affirmed by**

Organization	Yes or No	Question 8 Comment
		industry in a previous comment period. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners often work for a different company than the generation entity. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the turbine/speed governor model response matches the response from a recorded frequency excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. b. R1 should state that generation equipment OEM models are acceptable. This is the source of information we presently have for representing the dynamic response of our equipment. It is probably also the best source of data possible. **The OEM models are certainly a starting point and are more than adequate to comply with the requirements of MOD-012 and MOD-013. On the other hand, the SDT believes that verification requires a comparison of the simulation results against field measurements. Thus, the OEM models are not sufficient to comply with the requirements in this Standard, and recorded data, representative of the equipment response, is also needed.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Entergy Services, Inc		Entergy found this excerpt (section 4.2.1 bullet 2) below to be confusing, particularly the second sub-bullet below: o For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating);

Organization	Yes or No	Question 8 Comment
		and o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings. Could the SDT provide some examples of how this would work? **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability. **There are other standards or regional requirements, even interconnection agreements, that will determine which control modes are allowed and if the control could be changed during normal operation. This Standard aims at the verification of the response of the generation units following frequency disturbances. If the unit is switched to a control mode that renders it unresponsive to system frequency deviations, then it is still required to provide such information and associated documentation. But it should be recognized that switching to a different control mode might be a violation of other standards or requirements.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
FirstEnergy		FE offers the following comments and suggestions: 1. We are concerned that a regional or interconnection-wide excursion from the scheduled frequency may impact potentially an entity's entire generation fleet and the time frame of 365 days per R2 and Att. 1 may not be feasible. We ask the team to take this into consideration and add more time for these scenarios. **Based upon your comment, and others, we rethought the statement of periodicity and removed the requirement that verification be performed within 365 days of when the data are gathered. The revised Requirement R2 addresses when the**

Organization	Yes or No	Question 8 Comment
		model report and data are to be provided to the TP, not when the data are to be gathered, that detail is left to the GO. 2. Disturbance Monitoring Equipment (DME) necessary to obtain recorded data from excursions may be owned by the Transmission Owner and not the Generator Owner. The team may also want to consider how this MOD-027-1 standard is coordinated with the NERC PRC-002 DME standard that is still in development. The SDT believes only one entity can be assigned responsible for model verification and that entity should be the Generator Owner – a concept that was affirmed by industry in a previous comment period. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners often work for a different company than the generation entity. On the other hand, cooperation with the Transmission Owner is usually a good practice. Thus, if instrumentation is available to provide the necessary recorded data for the model verification, it is certainly beneficial to have such cooperation. But it should be noted that the instrumentation needed to comply with this Standard is much simpler and probably would not qualify as a DME, under the requirements of PRC-002. If a DME is available, most likely the recorded data would be sufficient to comply with the requirements of this Standard.
Response: The GVSDT thanks you for your comment. Please see responses above.		
Xcel Energy		For combined cycle steam turbines that operate with turbine control valves wide open it appears that verification is not required based on line 10 of Attachment 1. Is this a correct interpretation, or would it still need to be verified if the combustion turbine(s) supplying energy to the HRSG(s) respond to a frequency disturbance and cause the steam turbine output to respond, albeit with a very long time delay?

Organization	Yes or No	Question 8 Comment
Response: The GVSDT thanks you for your comment. In general, the combustion turbines are operated on speed governor control. Sometimes, the steady state droop settings on these combustion turbines try to compensate for the fact that the steam unit will not provide speed governor response, so the overall combined plant response meets system requirements (e.g. 4% or 5% droop). Thus, the combustion turbines would require the model verification, per the requirements of this Standard, while the steam turbine could be represented as "unresponsive" to frequency deviations. We have modified Attachment 1 to attempt to clarify that for units that do not respond to both under and over frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner.		
American Electric Power		In sections 4.2 Facilities - the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System"** In regards to the terms "Load Control" and "Active Power/Frequency Control" used throughout, more than the clarification of footnote 1 seems necessary. Does "load control" refer to turbine and boiler coordinated control? It is our experience that variable energy plants do not regulate active power or frequency. Appropriate models may not exist at the present time for either load control or active power/frequency control. If so, what then? **The SDT considers the representation of outer loop controls, particularly MW control loops, as an important element to properly represent the response of the turbine/speed governor following frequency disturbances. Thus, item 2.1.5 was included focusing specifically in this kind of component or control. The SDT will consider the inclusion of pressure limiters and/or emission control systems, as suggested, as part of the Standard.** **We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions (such as some variable energy plants), Requirement R2 is met with a written statement to that effect transmitted to the**

Organization	Yes or No	Question 8 Comment
		Transmission Planner. **The SDT also believes that models for new technologies will eventually become available, so that is not enough justification to grant an exception to this Standard. At least the documentation of the expected response and perhaps the recorded data associated with such response can always be prepared, even when this response cannot yet be simulated.** The grammar in the Purpose section could be simplified and made more clear. **The GVSDT attempted to write the purpose statement to apply to various technologies, and most of the industry found it acceptable. We considered but did not revise the purpose statement.** Should the implementation plan for the effective date of R1 precede the effect date for R3 through R5, by 90 days perhaps? **This is not necessary. Practically speaking activities associated with Requirements R3 through R5 will occur after Requirement R1.** R 2.2: Obtaining an aggregate model would only make sense if the units comprising that aggregate are at least similar if not identical to each other. This needs to be made clear. What happens if units whose response is to be aggregated are not similar? **The SDT has refined section 4.2.2 of the Facilities section under Applicability for clarity, and moved the verbiage for the optional use of individual and aggregate models individual units rated less than 20 MVA in plants to Part 2.1.** R 2.1.2: It would be beneficial to provide examples for "Type of governor and load control and active power control/frequency control equipment" in perhaps the same manner as MOD-026-1 R2.1.2.This comment form states "The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next." What is

Organization	Yes or No	Question 8 Comment
		meant by governor response not being consistent from one frequency excursion event to the next? Is this because of deadband or perhaps something else? **Reasons that the governor response is not consistent enough from one frequency excursion event to the next include the pre-contingency operating mode of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc.** M2 - it states "... Model was verified and dated evidence of transmission, , such..." we recommend changing the sentence to be "... Model was verified and dated evidence of transmittal, such..." **The GCDST has removed the extraneous comma per your suggestion. Thank you for your comment.** VSL - requirement 5 moderate VSL needs to be changed to say "but less than or equal to 150 calendar days." Also, the "or" statement in that column needs to be changed from "181 calendar days" to "151 calendar days" **The GVSDT agrees with your first suggestion and has revised the standard accordingly. The "or" statement has been revised so there is no reference to "calendar days".**
Response: The GVSDT thanks you for the comments. Please see responses above.		
Cowlitz County PUD		In the applicability section 4.2.2, second bullet states "comprised consisting." Cowlitz suggests deleting one of these words. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarify, including deleting the word " comprised " from the Applicability section.** Cowlitz also struggles with why the generation applicability is set at 75 MVA for the Western Interconnection. Is the SDT trying to encompass 80% of all Registered generation? Cowlitz abstains as it appears this standard may require information

Organization	Yes or No	Question 8 Comment
		that may not be possible to obtain, but can't offer technical basis at this time and will defer to commenters better equipped to answer. **The SDT is proposing to require verification of turbine / governor models associated with 80% or greater of the connected MVA per Interconnection.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons: (1) - Verification of identical units - The standard should address the verification of identical sister units. There is no reason to test two identical units. **The standard is written to provide for a "sister" unit verification allowance, though the word "sister" is not used as that use of language is too "folksy" for a standard. Please see Row 5 in Attachment 1 which discusses the scenario when an Existing applicable unit that is equivalent to another unit(s) at the same physical location".** (2) - 'Base Loaded' - The drafting team should clarify what is meant by 'base loaded'. Manitoba Hydro believes that it is important to verify base loaded units. **We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.** (3) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.

Organization	Yes or No	Question 8 Comment
		The verification of steady state MW and Mvar capabilities (MOD-025) would be accomplished by test which is distinctly different than the activities required for verification of dynamic models. Also, the verification of steady state MW and Mvar capabilities would be accomplished without taking the unit out of service. Personnel involved in steady state MW and Mvar capabilities will almost certainly be different than personnel involved in the verification of excitation control systems (MOD-026) or turbine/speed governors (MOD-027). Also, the verification of dynamic models will almost always be ten years, whereas the periodicity of steady state MW and Mvar capabilities per the current draft of MOD-025 and the generator protection and control coordination per the current draft of PRC-019 is only five years. The current drafts of MOD-026 and MOD-027 do have identical effective dates and periodicities.
Response: The GVSDT thanks you for the comments. Please see responses above.		
Public Utility District No. 1 of Clark County		MOD-027 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 25%, 50%, and 75% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-027. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Response: The GVSDT thanks you for the comments. The Effective Dates of the standard have been modified. The intent of the standard is that an entity with only one unit will comply within first four years. This is implied by the “at least” portion of the sentence.		
Seattle City Light		On-line monitoring is required to meet this draft Standard but is not yet available at all many generating plants. For the monitoring proposed, it will requires very high resolution Digital Fault Recorders that currently are not available nor required (side

Organization	Yes or No	Question 8 Comment
		note: as of right now in WECC existing generating plants below 1500 MW are not required to have DFRs, and many or most do not). The cost vs. benefit of such a demand should be reviewed and clarified.
Response **Thank you for your comment. The GVSDT believes that the verification of the turbine/speed governor models can be accomplished with records containing frequency and power output, with ideal sampling rates of 1 second or faster. Some entities have verified these models using sampling rates of 4, even 6 seconds. Some plants might have such recording capability in their turbine (digital) controllers or their plant SCADA system. For the turbine/speed governor models, the GVSDT does not believe that Digital Fault Recorders are mandatory.** **Besides, the on-line monitoring is not mandatory. Part 2.1.1 offers the options of partial load rejections (when applicable, see footnote) or speed reference setpoint step tests. Granted, there might be generation units where these two options are not feasible and, in such cases, the on-line monitoring becomes the only feasible option.**		
American Transmission Company, LLC		Please consider the following comments: 1. Applicability, 4.2.1, bullet 1 - As a Transmission Planner, ATC recommends that the unit size value be “20 MVA” rather than “100 MVA” and the aggregate plant size value be “75 MVA” rather than 100 MVA” to agree with the NERC Compliance Registry Criteria, which implies that the 20 MVA unit size and 75 MVA plant size values are large enough to be subject to the Reliability Standards. We are not aware of a definitive study that found the 100 MVA value to be appropriate for the Eastern Interconnection, particularly the upper Midwest portion of the system. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements**

Organization	Yes or No	Question 8 Comment
		for each interconnection for achieving this threshold. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. 2. In Requirements, R1, bullet 2 -ATC recommends to change the wording to, "obtain dynamic turbine/governor, load control, and active power/frequency control model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations". Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. Requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets, depending on the Generator Owner licenses or lack of licenses. **Response: Jason** **The second bullet has been revised accordingly. Also, the major software manufacturers have agreed to provide their models as described in Requirement R1. No later than by the effective date of the standard, software manufacturers' model information can be obtained from them by entering into the agreements they require.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
Los Angeles Department of Water and Power		Provide examples for methodology and data meeting the requirement for verification using historical operational data in accordance MOD-027-1 Requirement R2; 2.1.1 for frequency excursion from a system disturbance. **Requirement R2, Part 2.1.1 simply refers to graphic plots which compare the measured and simulated responses. Model validation consists of comparing the measured and simulated response. This requirement simply asks for providing those plots.**

Organization	Yes or No	Question 8 Comment
		In regards to: 4. “Applicability” 4.2.2 Generating units connected to the Western Interconnection with the following characteristics: o Individual generating unit greater than 75 MVA. This criteria seems to conflict with the Applicability requirement of MOD-025-2; **The verification of steady state Mvar capabilities (MOD-025) is distinctly different than the activities required for verification of governor and load control functions. Also, the verification of steady state Mvar capabilities and coordination of voltage regulating system controls would be accomplished without taking the unit out of service. The verification of governor and load control functions per the current draft of MOD-27 standards will be ten years.** 4.2.1, Individual generating unit greater than 20 MVA. Why are the generating unit MVA criteria different across the MOD Standards? **The SDT is proposing to require verification of dynamic models associated with 80% or greater of the connected MVA per Interconnection. This results in different MVA thresholds for different Interconnections. This philosophy has received industry support per questions asked in previous postings.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
ReliabilityFirst		ReliabilityFirst abstains and offers the following comments for consideration: 1. Facilities Section 4.2a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the “applicability” of this proposed standard. As a basis, the SDT recognized that the turbine / governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These**

Organization	Yes or No	Question 8 Comment
		models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor models, the SDT is proposing to require verification of models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. b. ReliabilityFirst requests clarification on why the term “Bulk Power System” is used rather than “Bulk Electric System.” ReliabilityFirst interprets, that by using the term “Bulk Power System”, units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. **GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.** 2. Requirement R1a. For the purposes of NERC standards, “bullets points” are to be considered “OR” statements. ReliabilityFirst believes all the “bullets points” in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) **The bullet points in R1 are intended to be bullets and as such, are meant to convey “or” statements. The reason is that these bullet points list information that the Transmission Planner will provide to the Generator Owner upon request from the Generator Owner.** 3. Requirement R4a. ReliabilityFirst seeks clarification on the rationale/justification for the 180 calendar day time period for the Generator Owner to provide revised model data to the Transmission Planner? ReliabilityFirst believes this data should be

Organization	Yes or No	Question 8 Comment
		provided within 90 calendar days consistent with other requirements in the standard (which require 90 calendar day submittals). **The GVSDT believes that 180 days is appropriate for Requirement R4 because it requires model data to be developed and transmitted in the event of changes made to a control system. More than 90 days may be necessary to accomplish the development verification. The requirements allowing 90 days are associated with providing instructions or readily available data (Requirement R1), written responses to comments (Requirement R3), or notification of model usefulness (Requirement R5). Also, it should be noted that an option allowed by R4 is a declaration that the GO will re-verify the model. If that is the case, Requirement R2 and Attachment 1 dictate the requirements and time lines for the subsequent model verification** 4. Proposed new Requirement R6a. ReliabilityFirst recommends the inclusion of a new Requirement R6 which would be a follow-up to Requirement R5. Requirement R5 requires the Transmission Planner to notify the Generator Owner if the model information is not useable (along with the technical description) but there is no corresponding requirement for the Generator Owner to make the model "useable" and submit it back to the Transmission Planner. ReliabilityFirst believes the feedback loop needs to be closed and a new Requirement R6 should be included. **Response:** **Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance.** **The GVSDT believes that these requirements (Requirement R5 for TP and Requirement R3 for GO) are sufficient to establish the proposed communication between these entities.**

Organization	Yes or No	Question 8 Comment
		5. VSLs - General format a. A number of VSLs use a parenthetical indicating the associated requirement number, some VSLs use the language "per R1", and other VSLs do not indicate the requirement number at all. ReliabilityFirst suggest using one consistent style/format and apply to all VSLs. **The GVSDT agrees with your comment and has revised the VSLs for consistency.** b. For consistency when referencing subparts, the VSLs should have the same nomenclature. For example, the VSL for R2 states "Requirement R2, Subparts 2.1.1, through 2.1.5." while the VSL for R5 states "Requirement R5, Parts 5.1 through 5.3." ReliabilityFirst suggest using the following format: "Requirement R1, Part 1.X". **The GVSDT has revised the VSLs to improve language consistency.** 6. VSL for Requirement R2 a. ReliabilityFirst recommends the language be consistent across all four sets of VSLs. For example the Lower VSL states "provided its verified model(s)" while the Severe VSL states "provided its verified turbine/governor and load control and active power/frequency control model(s)." ReliabilityFirst suggests using the language as stated in the Severe VSL for the other three VSLs. **The GVSDT has revised the VSLs for consistency.** b. There is no reference in the VSLs associated with Requirement R2, Part 2.2. ReliabilityFirst recommends adding a set of VSLs to cover a possible non-compliance with Requirement R2, Part 2.2. **The GVSDT has added the text "unit or plant aggregate" models to each Requirement R2 VSL for clarity and consistency.**
Response: The GVSDT thanks you for the comments. Please see responses above.		

Organization	Yes or No	Question 8 Comment
Tacoma Power		Requirement R2.1.5. It may be difficult to model the characteristics of outer loop controls (such as operator set point controls and load control) within the typical industry-standard modeling software parameters.
Response: The GVSDT thanks you for your comment. The outer loop control model is very important part of the model to obtain correct frequency response. Most software manufactures models include this control as an integral part of the model or a separate add on model.		
City of Vero		See response to Question 2 regarding the improper use of the term bulk power syst
Florida Municipal Power Agency		See response to Question 2 regarding the improper use of the term bulk power system
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
Tennessee Valley Authority - GO/GOP		Some consideration should be given for sister units if it can be demonstrated that the governor controls have identical settings. The 5% capacity factor threshold may be lower than necessary. Consider at least a 10% threshold since units which operate that infrequently are unlikely to be on line when a BES event occurs.
Response: Thank you. The "sister" or "proxy" unit concept is covered in Row 5 of Attachment 1 of the current draft of the standard allows consideration for an "unit that is equivalent to another unit(s)….."		
Georgia Transmission		Some of the requirements within this standard are confusing.

Organization	Yes or No	Question 8 Comment
Corporation		
Response: The GVSDT thanks you for your comment. The current draft of the standard has been re-worked for clarity. We hope this results in a standard that is clear and unambiguous.		
Northeast Power Coordinating Council		Some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical. The intent and goal of the SDT and MOD-027 are to achieve more accurate system modeling, and are to be supported. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the turbine / governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the dynamic models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor models, the SDT is proposing to require verification of dynamic models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate.** Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity

Organization	Yes or No	Question 8 Comment
		factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. **The GVSDT believes that units with less than 5% capacity factor are much less likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. The GVSDT is also aware of the fact that the very low capacity factor units will not be available for testing while operating at peak times, and it will be very expensive to test them at other times.** Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. **Please reference the response to the first part of your comment.** Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this what is intended? **The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The GVSDT modified the Effective Dates of the standard to be the same as in MOD-026. The intent of the standard is that an entity with only one unit will comply within first four years. This is implied by the "at least" portion of the sentence. Similarly an entity with four units will have to test at least 30% of the MVA in first four years to comply.** R2: There is linkage between the parenthetical "(within 365 calendar days from the date that the response was recorded)" and the reference in 2.2.1 "...unit's model

Organization	Yes or No	Question 8 Comment
		response to the recorded response for either....", but this language is not clear. The term "response" in the parenthetical needs to be clarified. **The GVSDT has modified Requirement R2 Part 2.1.1 to clarify that it is the MW response of the unit and reference to 365 has been deleted.** R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. Recommend the following wording to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc.), and any protection system controls (i.e. emission control systems on combustion turbines, etc.) effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that override the governor response (including blocked or non-functioning governors or modes of operation that limit the frequency response) if applicable. **After careful consideration and based upon the input from other industry members, the GVSDT did not feel that changing Requirement R2 Part 2.1.5 will add clarity.** R3: First bullet, term "usable" should be revised to "usable as defined in Requirement 5". Note that R5.1, 5.2 and 5.3 clearly define the criteria for "usable". **There is already a reference to Requirement R5 in the same bullet and GVSDT thinks it is not necessary to repeat it.** Section G References: Delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard. **The GVSDT believes that the references contain useful information from industry leaders regarding model verification and thus could be beneficial to many. The GVSDT does not believe that a list of relevant references will cause any confusion.**

Organization	Yes or No	Question 8 Comment
Response: The GVSDT thanks you for the comments. Please see responses above.		
Dynegy		The division of responsibility (between GO and TP) in the task of 'verifying' the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and 'verify' the models. This would also eliminate the question of what constitutes a 'verified' model, i.e., how good is good enough.
Response: The SDT considered who should be the owner of the model and asked Industry during the first posting. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. For all of these reasons, the SDT believes that the Generator Owner is the appropriate entity to perform model verification activities. Finally, as the owner of the model, the peer review Requirement R3 clearly states that the Generator Owner has the final say for any technical discussions regarding the model.		
SERC Dynamic Review Subcommittee (DRS)		The DRS found the excerpt below (section 4.2.1 bullet 2)to be confusing, particularly the second sub-bullet below: o For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating); and o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under**

Organization	Yes or No	Question 8 Comment
		Applicability to provide added clarity. Could the SDT provide some examples of how this would work? Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability. **Attachment 1 has been revised significantly to make it simpler and clearer. The intent is that if a unit does not have any governor control, it is important for transmission planner to know that so that its response can be modeled appropriately. How a GO operates a unit is beyond the scope of this standard.**
Response: Thank you for your comment. Please see responses above.		
Western Electricity Coordinating Council		The purpose statement appears to have an unnecessary word "that" immediately preceding the word accurately. After discussions with members of the drafting team WECC staff understands that the intent of the sub-sub-bullets in the applicability sections is intended to require that individual units greater than 20 MVA at generating plants greater than the identified Interconnection minimum be represented individually, while units less than 20 MVA at generating plants greater than the identified Interconnection minimum be represented as an equivalent, but WECC staff does not believe that intent is clearly reflected in the words in the sub-sub bullets. The sub-sub bullets in the applicability section use both "consisting of" (4.2.1) and "comprised of" (4.2.3) and use "consisting comprised of" in 4.2.2. The language should be consistent and the grammatical error in 4.2.2 should be corrected. **The SDT removed the word "that" (just before the word "accurately") from the Purpose Statement. The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** The Severe VSL for R2 includes providing required models more than 90 days late and also includes not providing models. It is not necessary to include the part about

Organization	Yes or No	Question 8 Comment
		not providing models. If models are never provided, they are more than 90 days late **The GVSDT agrees with your comment and has revised the standard accordingly.** The VSLs for R5 should use "less than or equal to" rather than just "less than" in the sections identifying how many days late the written response was provided. **The GVSDT agrees with your comment and has revised the standard accordingly.**
Response: Thank you for your comment. Please see responses above.		
Ingleside Cogeneration LP		We agree with the SDT's position that 80% of generation capacity in each Interconnection should be targeted for validation - not the 100% that some regulatory bodies might prefer. There is a careful balance between the costs to perform the validation and the expected reliability benefit which we expect to gain. We must look for cheaper alternatives for those generators which have a negligible impact on BES performance or serve non-critical load. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-027-1, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities.
Response: Thank you for your comment. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
ACES Power Standards Collaborators		We believe that this standard is overly administrative by memorializing the interactions between the Generator Owner and Transmission Planner that occur to model the generator's turbine/governor and load control and active power/frequency control systems. Most of the requirements are purely

Organization	Yes or No	Question 8 Comment
		administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. The FFT process represents one such effort to eliminate these backlogs. Interestingly, within the approval order for FFT, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard. Requirement R3 allows a Generator Operator to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems can be left unsolved. It should be struck. **Requirement R3 is a "peer review" type Requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process received over whelming support by Industry based on their responses in prior postings.** We are not convinced Requirement R4 is needed. **Requirement R4 specifies the need for model verification due to changes to the turbine/governor and load control and active power/frequency control that alter the equipment response characteristic. Without Requirement 4, there would be no trigger between the standard 10 year periodicity to update the model to reflect changes to the turbine / governor system.** The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is

Organization	Yes or No	Question 8 Comment
		referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of applicable control system changes. **Requirement R4 specifies the need for model verification due to changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic. Attachment 1 addresses the required periodicity and acceptable time delays to remain compliant.** In the first bullet under Requirement R3, we suggest referencing Requirement R5 regarding “useable” to make it clear that useable is in essence defined in Requirement R5. Otherwise, the reader may not realize that Requirement R5 sets the parameters on what “useable” is. We do not believe simply putting useable in quotes is enough. **There is already a reference to R5 in the same bullet and GVSDT thinks it is not necessary to repeat it.** The numbering of the section 4.2 is not consistent with the parallel MOD-026-1 standard. MOD-026-1 uses numbers for each sub-section while this standard uses primarily bullets. It would be easier to reference and comment if numbers are used rather than bullets and would be consistent. The second bullets of Sections 4.2.1, 4.2.2, and 4.2.3 are confusing and potentially contradictory. First, these sections state that they apply to each generating plant/Facility greater than 100, 75 and 75 MVA respectively. Then, the second sub-bullet (under the second bullet) applies to generating plant/Facility. How can there be a plant within a plant? With the first sub-bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 75 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for

Organization	Yes or No	Question 8 Comment
		individual generating units than first main bullets which apply to individual generating units. For example, the first main bullet in section 4.2.2 applies a 75 MVA threshold to an individual generating unit and then second sub-bullet applies a 20 MVA threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. The NERC Glossary of Terms uses a generator as an example of a Facility. In the second sub-bullet, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. The first main bullet under section 4.2.3 in the Facility section uses 50 MVA while the second bullet uses 75 MVA. This is not consistent with section 4.2.1 and 4.2.2 which use the same value for both bullets. Is this intentional? **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the standard applicability to provide added clarity.** The purpose statement appears to have an extra "that". It begins with "that accurately represent" and is in the second to last line. **The GVSDT thanks you for your comment and made the correction.** Part 2.1 includes an ambiguous statement about using a model that is acceptable to the Transmission Planner. We assume the intent was for the Generator Owner to use a model identified by the Transmission Planner in Requirement R1. If so, we suggest changing "acceptable to the Transmission Planner" to "identified in Requirement R1". Otherwise, the Generator Owner may be compelled contact the Transmission Planner for an attestation that the model is acceptable. This further ensures that everyone (registered entity and auditors) interprets that language to mean those models identified in Requirement R1. **Requirement R2 contains the words "acceptable to Transmission Planner" since Requirement R1 may not apply in many cases. A Transmission Planner responds only if requested by GO to provide such information.** We appreciate the drafting team's consideration in Attachment 1 to allow a unit that has already verified its turbine/governor and load control and active

Organization	Yes or No	Question 8 Comment
		power/frequency control models to be considered compliant. However, it is not clear how this helps. How does the Generator Owner demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff be sufficient? Will the regional entities be willing to validate that they have confirmed regional criteria? **Using evidence from verifications prior to the standard becoming effective requires that appropriate evidence has been retained by the GO as specified in section D.1.2. Lacking such evidence, the units will be assumed to have never been validated. As always, the ultimate decision concerning compliance will be up to the RRO auditors and enforcement staff. It is suggested that this question be referred to your RRO staff following standard approval, and you can plan your validation program accordingly.** We do not believe the VRF Requirement R5 should have a Medium VRF. It is an administrative requirement that is focused on notifying the Generator Owner as to the suitability of the model they provided. **From the VRF Guideline, a Medium Risk Requirement is:** **“A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.”**

Organization	Yes or No	Question 8 Comment
		Requirement R5 is linked directly to Requirement R2 and is a confirmation that a verified model is useable to plan the BES. If a verified model is provided by the Generator Owner, the Transmission Planner must determine whether or not the model is useable. If this step in the process is missing, then the validity and usefulness of the model is uncertain. Using uncertain models can lead to the BES being improperly planned and could "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system." **Therefore, Requirement R5 is assigned a Medium VRF.** All of the measurements use language that sounds like a requirement and is not consistent with language used in any other NERC standard. They all use "must include". It is more typical to use "shall demonstrate", "shall make available", etc. These measurements should be made consistent with other NERC standards. **The SDT believes the measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. It should be noted that this is consistent with NERC guidelines and support documentation for drafting Standards. A review of the measures did result in some corrections and clarifications.** All of the measurements use language that requires proof of transmission of the communication. Some examples of the proof include data postal receipts, dated confirmation of facsimile, etc. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. Reports on email failures are

Organization	Yes or No	Question 8 Comment
		separate reports. **The examples were offered as such: these are examples. The SDT understands that the different regions and different entities will have their specific protocols for the requirements associated with NERC Standards. As such, these methods and examples are just to illustrate the flow of information, as the SDT perceives it. These methods and examples are not part of the Requirements, but listed in the Measures. Once again, the methods listed in the Measures are for reference, but are not intended to be an exhaustive and comprehensive list of the possible ways in which this could be implemented.** The Compliance Enforcement Authority section is not the latest approved language being used by NERC. **The Compliance Enforcement Authority language was updated to reflect the latest NERC Standards template language.** We question the need to retain the “latest and previous turbine/governor and load control and active power/frequency control system model verification” as it seems excessive evidence retention. This could require Generator Owner’s to retain evidence for greater than twenty years which greatly exceeds the six-year audit cycle. Thus, it would not even be reviewable in an audit per the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C - Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Given that the cycle for compliance exceeds the audit cycle for Generator Owners of six years, we think the drafting team should work with NERC compliance to consider how the auditing of the standard will occur. **We concur and have removed “and previous” from the Data Retention bullet pertaining to the Generator Owner for Requirement R2.** Some small entities will have audits in which no generator will have to be verified. Should this requirement even be actively monitored or should it only require proof

Organization	Yes or No	Question 8 Comment
		of compliance during investigations? **The standard is written to be size-neutral with respect to the number of units an entity may own and the size of those units. If an entity does not have any units verified during an audit period, then this would be reported for compliance.** We have identified several issues with the periodicity table in Attachment. First, the table is referred to as the periodicity table in the examples that accompany the unofficial comment form. It is not titled as such in the actual document. We believe a title would be appropriate for clarity. Second, Row 4 is not really a triggering event as the first column describes but rather a set of conditions that allow a Generator Owner to utilize an already verified unit model for a similar unit. Third, as written Row 5 only will apply when non-compliance occurs. For instance, Row 5 only applies when the 11 year period (10 year plus one year grace period) for Row 1 or Row 2 has been violated. We agree with the concept of that Row 5 presents in that a frequency event may not have occurred but the other Rows need to be clarified so that it does not present a non-compliance. Fourth, the first part of row 10 is also not really a triggering event but an exception. **We made extensive revisions to Attachment 1 to address your concerns and others.**
Response: Thank you for your comment. Please see responses above.		
ISO New England Inc.		We feel that some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical.
Response: As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized		

Organization	Yes or No	Question 8 Comment
that the turbine / governor system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor system models, the SDT is proposing to require verification of dynamic models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the turbine/governor and load control and active power/frequency control models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard. Also, the SDT does recognize that Regional Variances can be considered if a Region desires to include additional unit MVA in this standard.		
Kansas City Power & Light		Should replace “bulk power system” with “Bulk Electric System”. Use of “bulk power system” is ambiguous where as “Bulk Electric System” is fully defined.
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.		
Oncor Electric Delivery Company		No
SERC Generation Subcommittee		No comment

Organization	Yes or No	Question 8 Comment
Puget Sound Energy		None
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.

PRC-019 Summary Consideration: Stakeholders provided feedback to make improvements to the standard and the GVSDT incorporated many of them in the standard.

A large majority of stakeholders agreed that the Applicability as drafted was correct. A significant minority of stakeholders felt that the use of the term "bulk power system" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. A number of stakeholders objected to the inclusion of synchronous condensers and black start units. The SDT did not find that valid technical arguments were presented to remove these units from the Applicability and did not make the change.

A large majority of the stakeholders agreed with the revisions made to the examples in Section G. Exelon objected that the wording in the examples implied that the Steady State Stability Limit had to be calculated based on a fixed field current. The SDT modified the wording so that the SSSL can be calculated either with fixed or variable field current. Luminant objected to the inclusion of phase distance relay characteristics on the example graphs. The SDT agreed to remove these parameters from the graphs. Dominion asked the SDT to further clarify that the coordination does not apply to all generator protective functions. The SDT revised the wording to further clarify that concept. PPL asked for an all inclusive list of limiters and protective functions to be coordinated. The SDT declined this request as stakeholders might view it as being too prescriptive.

Several stakeholders objected to the 5-year interval for verifying coordination. The SDT felt the stakeholders did not present valid reasoning for extending the interval and did not change it. Several stakeholders argued that the risk associated with non-coordination did not warrant a "High" VRF. The SDT felt the arguments were valid and revised the VRF level for both Requirements R1 and R2 to "Medium". Several stakeholders felt the VSL language did not match the requirements, or questioned the tardiness intervals. The SDT agreed that the wording in the VSL's needed revision and made the suggested changes. The SDT did not change the tardiness increments in the VSL's since they come directly from NERC guidelines. Some stakeholders objected that the Effective Date section was too restrictive for entities with a small number of units. The SDT agreed and modified the first step of implementation to extend to two years instead of one and cover 40% of the applicable units.

9. **The GVSDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 20 MVA. The standard applies to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 20MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the comment area below.**

Summary Consideration: A large majority of stakeholders agreed that the Applicability as drafted was correct. A significant minority of stakeholders felt that the use of the term "bulk power system" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. A number of stakeholders objected to the inclusion of synchronous condensers and black start units. The SDT did not find that valid technical arguments were presented to remove these units from the Applicability and did not make the change.

Organization	Yes or No	Question 9 Comment
Seminole Electric Cooperative, Inc.	Negative	a) 4.2: BPS is not a NERC defined Term in the NERC Glossary of Terms **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** b) Section C, M-1, The term "protective functions" is too broad. The specific functions should be clarified. **The SDT has added the word "applicable" before functions in Requirement R1 and Measure M1 to limit the scope to those protective functions that affect the coordination between limiters, protection and equipment capabilities.** c) Section C, M-1, Does the term "protection system" apply to the defined NERC term? **Yes, the term "Protection System" refers to the definition in the NERC Glossary of Terms.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
CPS Energy	Negative	Are variable generating units such as wind, solar, and Hyrdo included or excluded from the "applicable facility" term.
Response: The GVSDT thanks you for your comment. They are included. The standard is technology neutral.		

Organization	Yes or No	Question 9 Comment
Beaches Energy Services	Negative	PRC-019 The Applicability, Facilities section 4.2 can be deleted since this is just a repeat of the SCRC.
Response: The GVSDT thanks you for your comment. The inclusion of synchronous condensers makes it necessary to clarify the applicability.		
City of Green Cove Springs, Kissimmee Utility Authority	Negative	The Applicability, Facilities section 4.2 can be deleted since this is just a repeat of the SCRC.
Response: The GVSDT thanks you for your comment. The inclusion of synchronous condensers makes it necessary to clarify the applicability.		
JEA	Negative	The inclusion of a four 15 MVA units at a facility will not need to be verified and yet a single 20 MVA unit will need to be verified. Suggest making a consistent rule of 75 MVA for both single and aggregate units. Also black-start units should be removed since they are only used during emergency conditions and are already tested to verify that they can start their intended load.
Response: The GVSDT thanks you for your comment. The SDT elected to follow the NERC Registration Criteria for the applicability of PRC-019. The ability to supply dynamic reactive power and control voltage is important during system restoration and black-start units are included in this standard to assure that voltage regulating controls, limit functions, and protection systems are coordinated.		
Clark Public Utilities	Negative	The standard needs to recognize there are generator owners and transmission owners that have only a few applicable facilities and the percentage fulfillment requirement in the effective date section. Please fix it now before the standard is approved.
Response: The GVSDT thanks you for your comment. Paragraphs 5.1.1 and 5.2.1 of the Effective Date section have been revised to two years in recognition of entities with few units that may have outage schedules that extend past one year. The use of "at least" in each of the Effective Date subsections recognizes generator and transmission owners with a limited number of facilities. For		

Organization	Yes or No	Question 9 Comment
example, a generation owner with only 3 facilities will need to verify two facilities by the first day of the first calendar quarter, two calendar year following approval. The third facility will need to be verified by the fourth year.		
Southern Company	No	1) Applicability, Section 4: Applicability for PRC-019 and MOD-025 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to individual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to be focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their criticality to the system seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where reliability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. The individual unit size criterion should match the aggregated plant size criterion.
Response: The GVSDT thanks you for your comment. The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.		
ExxonMobil Research and Engineering	No	: A model's validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit's response.
Response: The GVSDT thanks you for your comment. It appears to the SDT that this comment is made in reference to MOD-027.		

Organization	Yes or No	Question 9 Comment
Please see the response provided to this same comment provided in Question 6.		
Duke Energy	No	o Comments: We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. **The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.** o Sections 4.2.1, 4.2.2, 4.2.3 - replace “bulk power system” with “Bulk Electric System (BES)”. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Transmission Access Policy Study Group	No	As stated with respect to MOD-025 in TAPS response to Question 2 above, the Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of PRC-019 be revised as follows: “For the purpose of this standard, the term, ‘applicable Facility’ shall mean ‘BES generator.’ For the purpose of this standard, a synchronous condenser is treated as a generator.”
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has		

Organization	Yes or No	Question 9 Comment
modified the standard accordingly. The inclusion of synchronous condensers makes it necessary to explicitly specify the full applicability.		
Cowlitz County PUD	No	Cowlitz believes 20MVA is meant to catch users who may adversely affect the BES, such as via a faulty BES Protection System a small generator may own. The registry criteria should not endeavor to identify generation that is necessary for the support of the BES. Cowlitz feels this standard applicability conflicts with Phase 2 of Project 2010-17, Definition of Bulk Electric System. This standard should only apply to BES generation which currently is poorly defined. If this standard is needed urgently to cover a Reliability gap, Cowlitz would suggest an arbitrary 200 MVA applicability be established and a phase 2 SAR be established to adjust the standard to apply to BES generation after completion of Project 2010-17. Cowlitz commends and thanks the SDT in addressing this question.
Response: The GVSDT thanks you for your comment. The SDT agrees that the standard only applies to the BES and has changed the wording accordingly. The SDT feels that the Applicability section appropriately identified which facilities must comply with the standard.		
AECI	No	I Believe that the Ratting should be 100 MVA for all Generating units
Response: The GVSDT thanks you for your comment. The SDT feels that limiting the applicability to generating units 100 MVA and larger would fail to adequately assure reliability.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP has not changed its position that PRC-019-1 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System - and this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of

Organization	Yes or No	Question 9 Comment
		the BES takes effect.
Response: The GVSDT thanks you for your comment. The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.		
Pepco Holdings Inc and Affiliates	No	Same comments as in Question 2.
Public Service Enterprise Group (PSEG)	No	See comments to Question 2 above.
Florida Municipal Power Agency	No	See response to Question 2
City of Vero	No	See response to Question 2
Wisconsin Electric Power Company	No	The Applicability section in 4.2 refers to generators being connected to the “bulk power system”, or BPS. The reference should be to the Bulk Electric System (BES), which is defined by NERC. The BPS is not a defined term in the NERC Glossary, and using this term is extremely confusing and possibly misleading. The GVSDT’s use of the term BPS, here and in several other standards, opens the door for applying NERC standards to generating units which are connected to the system at voltages below 100 kv. The applicability should solely be to generating units of the MVA size required for registration and connected to the BES at 100 kv or higher, and to those generators which are blackstart resources.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly. The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and		

Organization	Yes or No	Question 9 Comment
protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.		
Tennessee Valley Authority - GO/GOP	No	The MVA criteria included in MOD-026-1 and MOD-027-1 are more appropriate for this standard than the 20 MVA criteria presently used. A 20 MVA unit is not critical enough to the BES reliability to justify this level of documentation of coordination. Standard PRC-004 already requires an investigation into relay misoperations for units greater than 20 MVA which would be the result of coordination issues.
Response: The GVSDT thanks you for your comment. The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.		
Northeast Power Coordinating Council	No	This Standard is applicable to generating units/facilities that meet the compliance registry criteria. However, this Standard is not applicable to any type of synchronous condensers. The purpose for synchronous condensers is to provide voltage support as needed, similar in function to a capacitor bank or shunt reactor.
Response: The GVSDT thanks you for your comment. The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.		
ACES Power Standards Collaborators	No	We disagree with the need to include Blackstart Resources within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already

Organization	Yes or No	Question 9 Comment
		requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during a restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. **The ability to supply dynamic reactive power and control voltage is important during system restoration and black-start units are included in this standard to assure that voltage regulating controls, limit functions, and protection systems are coordinated.** The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies the standard to facilities that NERC has

Organization	Yes or No	Question 9 Comment
		already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. **The inclusion of synchronous condensers makes it necessary to explicitly specify the full applicability.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Dominion- NERC Compliance Policy	Yes	Dominion agrees, but points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2.
Response: The GVSDT thanks you for your comment. The inclusion of synchronous condensers makes it necessary to explicitly specify the full applicability.		
Ameren	Yes	The VRF and VSL need to be modified to put the significance to BES reliability in proper perspective; refer to our comments in response to question 11.
Response: The GVSDT thanks you for your comment. The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.		
Southwest Power Pool Standards Development Team	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 9 Comment
Imperial Irrigation District (IID)	Yes	
FirstEnergy	Yes	
PPL	Yes	
Puget Sound Energy	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of	Yes	

Organization	Yes or No	Question 9 Comment
Clark County		
Los Angeles Department of Water and Power	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Seattle City Light	Yes	
American Electric Power	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc	Yes	
Seattle City Light	Yes	
Kansas City Power & Light	Yes	
Tacoma Power	Yes	None
SERC Generation Subcommittee		No comment

Organization	Yes or No	Question 9 Comment
SERC Dynamic Review Subcommittee (DRS)		No comment
Indiana Municipal Power Agency		No comment

10. **The GVSDT revised section G based on stakeholders' comments to provide clarity and to indicate that the items listed are examples of coordination and that entities may provide "Equivalent tables or other evidence." Do you agree with the revisions to Section G? If not, please explain in the comment area below.**

Summary Consideration: A large majority of the stakeholders agreed with the revisions made to the examples in Section G. Exelon objected that the wording in the examples implied that the Steady State Stability Limit had to be calculated based on a fixed field current. The SDT modified the wording so that the SSSL can be calculated either with fixed or variable field current. Luminant objected to the inclusion of phase distance relay characteristics on the example graphs. The SDT agreed to remove these parameters from the graphs. Dominion asked the SDT to further clarify that the coordination does not apply to all generator protective functions. The SDT revised the wording to further clarify that concept. PPL asked for an all inclusive list of limiters and protective functions to be coordinated. The SDT declined this request.

Organization	Yes or No	Question 10 Comment
Exelon	No	Exelon does not believe the SDT adequately addressed the concern previously raised by Exelon regarding Section G as documented in the Consideration of Comments on Generator Verification (PRC-019-1) - Project 2007-09 dated 2/22/12 (p 18). The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (page 7) states "[f]or the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current." This conflicts with Requirement R1.1.1 that states "... assuming normal AVR control loop and system steady state operating conditions." Currently the two statements are in conflict with one another in that one requires a "fixed" field current (i.e., AVR in "manual") and the other requires "normal operation" (i.e., AVR in "automatic"). The response given by the SDT was that "[t]he SDT agrees that the generators must normally operate in AVR mode." This does not address the conflict identified. The SDT needs to allow for automatic mode for AVR to accommodate those generating units that have redundant automatic channels as is the case for newer digital AVRs. This will allow the Generator Owner to use AVRs automatic mode when plotting SSSL. The response given by the SDT was that "[t]he calculation of the SSSL, based on a fixed-field current value, is a typical industry practice and provides a conservative number to be used for

Organization	Yes or No	Question 10 Comment
		coordination purposes without making calculations overly complex..."Exelon does not believe this response is acceptable. PRC-019-1 should not force a Generator Owner to use the SSSL curve with the AVR in "manual". There should be an option that allows a Generator Owner to use the SSSL curve with the AVR in "manual" or in "auto." If the Generator Owner wants to use a more complex calculation to plot SSSL curve with the AVR in "auto" (which although more complex would also be more accurate) it should be left to the discretion of the Generator Owner.
Response: The GVSDT thanks you for your comment. The use of the SSSL curve in the example found in Section G is based on a conservative method of determining minimum excitation limiter settings that will result in maintaining stability of the unit in the event of a trip of the AVR from auto to manual while in steady state operation. The wording used in the example of Section G has been modified to allow an entity to calculate the SSSL curve with the excitation control system in auto, if they choose.		
Luminant Energy Company LLC, Luminant Power	No	Luminant disagrees with the need to illustrate coordination of the phase distance relay with AVR controls. The sample R-X diagram does not indicate how the relay is coordinated with field forcing capability. Since this function is covered in the generator loadability standard currently under development, Luminant recommends that this function be removed from the R-X diagram.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comment and has removed the impedance relay from the attachment example. Also, the example attachments have been simplified and enhanced.		
Dominion- NERC Compliance Policy	No	Section G provides additional clarity. However, the Purpose, R1.1 and Section G do no fully align. It should be made clear that all generator protection system devices aren't applicable.
Response: The GVSDT thanks you for your comment. R1.1 identifies the scope to be the following "…the voltage regulating system controls, (including In-service 2 limiters and protection functions) with the applicable Facility capabilities and Protection System settings….". The intention of Section G is to provide some examples of evidence that will support a claim that the		

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Organization	Yes or No	Question 10 Comment
elements itemized in R1.1 are coordinated. Each of the elements appearing on the examples of Section G are either parts of the voltage regulating system controls, the Facility capabilities, or the generator Protection System. The wording "settings of the applicable Protection System devices as referenced in Section G" has been added to provide limits on the scope of the verification of settings covered in this standard.		
PPL	No	The draft standard is technically sound, but additional clarity may be needed to enforce it in a uniform and unambiguous fashion. The GVSDT should list in section G all relays and associated excitation system and voltage regulator functions that, if present and active, are covered by this standard.
Response: The GVSDT thanks you for your comment. The scope of the limiters and protection elements included in the draft standard are those elements that are in-service at each entities facility where mis-coordination could result in a unit tripping before limiting, excessively damaging equipment due to continually operating beyond equipment capabilities before tripping the unit. In each of these cases, the system reliability is unnecessarily reduced. If the limiter and protection elements are not in-service, then they are not applicable.		
Kansas City Power & Light	No	This assumes that the auditor will have the protection skills and knowledge necessary to confirm that "other evidence" is equivalent to the plots shown in the attachment one examples.
Response: The GVSDT thanks you for your comment. You are correct; this burden is the responsibility of the Regional Compliance Monitoring and Enforcement entities.		
Wisconsin Electric Power Company	Yes	It is not clear how the field current limiters or trip settings are plotted on the P-Q diagram, since these parameters are dc field amps.
Response: The GVSDT thanks you for your comment. Characteristics of limiters or protection that operate on field amps can be shown on a P-Q diagram through the use of supplied generator data (i.e. V-curves, etc.). There are published technical papers on this subject, such as "Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee. The SDT has added some of these references to Section		

Organization	Yes or No	Question 10 Comment
F of the standard.		
Manitoba Hydro	Yes	Manitoba Hydro suggests that example curves be provided for variable generation plants.
Response: The GVSDT thanks you for your comment. The SDT believes the examples provided are adequate for representation. The GO's of VER equipment could use VER specific technical data and/or graphs as evidence for M1.		
American Electric Power	Yes	On the P-Q diagram, it is not clear how the instantaneous field current and instantaneous field current trip shown in the diagram would be relevant to coordination. These two values are not typically provided in such a diagram.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comment, the instantaneous field current limit and instantaneous field current trip are not necessary to show coordination. Attachment 1has been changed to remove these characteristics. However, a GO entity may have these functions activated and could plot them on a common graph.		
Ingleside Cogeneration LP	Yes	We agree that it is appropriate to add a statement to the P-Q and R-X diagrams that they show performance at nominal voltage and frequency levels. We also agree that the SSSL calculation should be based upon a fixed field current value, even if it does not take into account the action of the AVR in automatic mode. It is a far less complex method to use and returns a more conservative value in any case. Ingleside Cogeneration would like to commend the SDT's for holding to its position that there is no need to complicate the analysis by assessing performance under transient conditions or single contingency scenarios. In our view, there is no justification to adding time and effort to an initiative until data shows that it will result in a tangible reliability benefit.
Response: The GVSDT thanks you for your comment.		
ACES Power Standards Collaborators	Yes	We believe it is reasonable to include examples of satisfactory evidence. It helps to highlight the intent of the drafting team.

Organization	Yes or No	Question 10 Comment
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Standards Development Team	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
Imperial Irrigation District (IID)	Yes	
FirstEnergy	Yes	
Puget Sound Energy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 10 Comment
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group (PSEG)	Yes	
Xcel Energy	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Ameren	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 10 Comment
Cowlitz County PUD	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
Seattle City Light	Yes	
Tacoma Power	Yes	None
SERC Generation Subcommittee		No comment
SERC Dynamic Review Subcommittee (DRS)		No comment
Indiana Municipal Power Agency		No comment

11. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-019-1?

Summary Consideration: A significant number of stakeholders felt that the use of the term "bulk power system" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. Several stakeholders objected to the 5-year interval for verifying coordination. The SDT felt the stakeholders did not present valid reasoning for extending the interval and did not change it. Several stakeholders argued that the risk associated with non-coordination did not warrant a "High" VRF. The SDT felt the arguments were valid and revised the VRF level for both Requirements R1 and R2 to "Medium". Several stakeholders felt the VSL language did not match the requirements, or questioned the tardiness intervals. The SDT agreed that the wording in the VSL's needed revision and made the suggested changes. The SDT did not change the tardiness increments in the VSL's since they come directly from NERC guidelines. Some stakeholders objected that the Effective Date section was too restrictive for entities with a small number of units. The SDT agreed and modified the first step of implementation to extend to two years instead of one and cover 40% of the applicable units.

Organization	Yes or No	Question 11 Comment
Indiana Municipal Power Agency	Abstain	IMPA is not voting negative on this standard, but we do believe that this standard adds additional expense and administrative burden on many smaller entities without any significant increase to the Bulk Electric System. In addition, we do not see the benefit of performing this analysis every five years if nothing has changed with the equipment (the equipment has not been changed or replaced).
Response: The GVSDT thanks you for your comment. The SDT believes there is a reliability benefit to having protection, limiters, and equipment capabilities properly coordinated. There is no need to recalculate all of the numbers every five years if the entity verifies that the settings and capabilities have not changed. It is possible that the SSSL may change without knowledge of the GO. It is prudent to ensure that coordination with that limit exists. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system		

Organization	Yes or No	Question 11 Comment
characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of ‘bulk power system’ to ‘Bulk Electric System’ would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The SDT has replaced the term “bulk power system” with “Bulk Electric System”.		
Consolidated Edison Co. of New York	Affirmative	See Individual Company and NPCC group comments
BC Hydro and Power Authority	Negative	BC Hydro is voting Negative as the basis for the 5 year recurring requirements of R2 are not clear. BC Hydro recommends either providing more detailed supporting justification or taking a more balanced approach ie conduct the review upon identification or implementation of systems, equipment or setting changes that are expected to affect this coordination.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Northern Indiana Public Service Co.	Negative	Confusion since the Bulk Power System (BPS) and Bulk Electric System (BES) are both mentioned within these standards; they are not the same

Organization	Yes or No	Question 11 Comment
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Great River Energy	Negative	Great River Energy agrees with the comments of the MRO NSRF and ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please see the SDT responses to the MRO NSRF and ACES Power Marketing.		
Essential Power, LLC	Negative	In R1, it is unclear with whom the coordination is conducted. The requirement reads as if the GO or TO is required to coordinate with their own facility. I recommend that the SDT revise the language to make it clear as to who is involved in the coordination. In regards to the facilities to which this Standard is applicable, the term 'bulk power system' used in section 4.2 is ambiguous and is not defined in the current, approved version of the NERC Glossary of Terms. The term should be changed to 'Bulk Electric System', as defined in the Glossary.
Response: The GVSDT thanks you for your comment. The "coordination" specified within R1 is a technical term commonly used in protective relaying departments for a comparative evaluation of the set points and operating characteristics for control equipment and protective relaying equipment. The use of this word here is that connotation rather than one associated with communication between two parties. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Seattle City Light	Negative	New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.

Organization	Yes or No	Question 11 Comment
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Old Dominion Electric Coop.	Negative	Not sure that R2 is written correctly... GO and TO to verify their own verification every five years. Just tell them they must do it every five years, Regions/NERC/FERC should be verifying.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Omaha Public Power District	Negative	OPPD supports MRO NSRF comments
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Dairyland Power Coop.	Negative	Please see comments submitted by MRO NSRF.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Muscatine Power & Water	Negative	Please see the comments submitted by NSRS for Project 2007-09 Generator Verification.
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.

Organization	Yes or No	Question 11 Comment
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Tenaska, Inc.	Negative	PRC 019 could be difficult to implement given the limited AVR interface/control provided to users by OEMs. More flexibility may be needed in some circumstances.
Response: The GVSDT thanks you for your comment. The SDT assumes the commenter is referring to digital AVR's. If the commenter did not obtain the proper software to interface with the AVR when it was purchased, then there should at least be a commissioning report that specifies the limiter settings. If the entity cannot access these settings, then by default they will not be changed. It is possible that the SSSL may change without knowledge of the GO. It is prudent to ensure that coordination with that limit exists		
Seattle City Light	Negative	Q11. New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		

Organization	Yes or No	Question 11 Comment
Brazos Electric Power Cooperative, Inc.	Negative	See ACES Power Marketing comments.
Midwest ISO, Inc.	Negative	See comments submitted by MRO NSRF.
New Brunswick System Operator	Negative	See comments submitted by NPCC Reliability Standards committee.
Florida Municipal Power Pool	Negative	See FMPA comments
Lakeland Electric	Negative	See FMPA comments.
Central Electric Power Cooperative	Negative	see Matt Pacobit’s comments from AECI
N.W. Electric Power Cooperative, Inc.	Negative	see Matt Pacobit’s comments from AECI
KAMO Electric Cooperative	Negative	See Matt Pacobit's comments from AECI
Northeast Missouri Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
M & A Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI.
Sho-Me Power Electric Cooperative	Negative	See Matt Pacobit's comments from AECI.
U.S. Army Corps of Engineers	Negative	See MRO/NSRF comments.

Organization	Yes or No	Question 11 Comment
Public Utility District No. 1 of Lewis County	Negative	Thank you for the opportunity to comment on the proposed standard PRC-019-1. Our utility owns and operated a smaller run-of-river hydroelectric plant with two 35MW units. While I am a firm believer in testing, it can be over done. Many of the new relays and AVR's are electronic based and do not change over the years. Initial plant setup normally verifies coordination of the relaying and ARV limits. Therefore I suggest changing testing requirements in R2 to no more often than 10 years for electronic AVR systems. Classes or training in NERC generator and unit testing in Project 2007-09 would be helpful to Generator Owners, especially smaller GO's.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Clark Public Utilities	Negative	The effective date section of the standard provides a confusing implementation for a utility that has only one generator. Please address this issue. I suggest that you add the following to end of section 5.1.5, "This section applies to a Generator Owner and Transmission Owner having only one applicable facility."
Response: The GVSDT thanks you for your comment. The SDT disagrees that five years are necessary to perform the required activities on one generator. However, the SDT has modified the implementation schedule to remove the first step (20% in one year), so that entities with one or two units and outage schedules longer than one year will have two years to complete the activities on the first generator.		
Southwest Transmission Cooperative, Inc.	Negative	The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the “verify the existence of the coordination” from Requirement R2. Requirement R1 uses “shall coordinate”. **The SDT has revised R1 and the**

Organization	Yes or No	Question 11 Comment
		wording in the VSL's accordingly. Additional VSLs were added based on increments of tardiness. We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Sunflower Electric Power Corporation	Negative	The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the "verify the existence of the coordination" from Requirement R2. Requirement R1 uses "shall coordinate". We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement

Organization	Yes or No	Question 11 Comment
		at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF.
Response: The GVSDT thanks you for your comment. The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.		
Independent Electricity System Operator	Negative	There is only a SEVERE VSL assigned to Requirement R1, for the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1. This condition does not appear to be consistent with the intent of Requirement R1, which requires the responsible entities to coordinate the voltage regulating system controls, (including In-service limiters and protection functions) with the applicable Facility capabilities and Protection System settings. The parts that follow also prescribe the actions need for verification, not the identification of the existence of the verification information. **The SDT agrees. The GVSDT has revised the VSLs to include increments of tardiness for each level.** The SEVERC VSL for Requirement R2 includes the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years. This condition is almost identical to the SEVERE VSL for R1, except it has a time component associated with the failure. A failure to verify the existence of the coordination specified in Requirement R1 in more than 6 years, despite it might have implemented the verification exercise stipulate din R1, can subject an entity to being found non-compliant twice. This is not acceptable. **Requirement R2 has been restructured so that it only involves addressing changes to the settings or equipment that will affect coordination. The time frame is much different and the VSL's for Requirement R2 have been restructured accordingly.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		

Organization	Yes or No	Question 11 Comment
Southwest Transmission Cooperative, Inc.	Negative	We disagree with the need to include Blackstart Resources within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during a restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. **The SDT disagrees that Blackstart Resources should be removed from the applicability of this standard. When called upon to operate in their blackstart mode, it would probably be under stressed transmission system conditions that could require the generator to provide reactive power to its limits (either leading or lagging). Given the critical nature of an actual transmission system recovery, having the blackstart generator limiters and protection properly coordinated is essential.** The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on subtransmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion

Organization	Yes or No	Question 11 Comment
		of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies the standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. We believe it is reasonable to include examples of satisfactory evidence. It helps to highlight the intent of the drafting team. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** We do not believe Requirement R2 as written accomplishes the reliability purpose. Isn’t the purpose of R2 to compel registered entities to re-verify coordination every five years along with changes to “systems, equipment or setting changes” within 90 days? We do not believe “shall verify the existence of coordination” accomplishes this. We believe that it only compels the registered entity to verify the coordination was performed at some point. It does not compel the entity to verify that coordination reflects current conditions such as Protection System settings. We suggest changing “shall verify the existence of coordination” to “shall coordinate”. Furthermore, we think some of the confusion could be eliminated by including the five-year periodicity in Requirement R1 and focusing Requirement R2 on system and equipment changes. **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind**

Organization	Yes or No	Question 11 Comment
		(equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1. Section D.1.1 needs to be updated to reflect that latest approved language for the Compliance Enforcement Authority. **The SDT believes that "Regional Entity" is the proper Compliance Enforcement Authority and declines to make a change.** The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the "verify the existence of the coordination" from Requirement R2. Requirement R1 uses "shall coordinate". **The SDT agrees and has revised the wording in the Severe VSL for Requirement R1 to say "… failed to coordinate equipment capabilities, limiters, and protection…".** We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		

Organization	Yes or No	Question 11 Comment
Modesto Irrigation District	Negative	We strongly support generator testing and verification, and coordination with protection systems. However, the use of the undefined term "bulk power system" in the standard will lead to needless confusion. Also, we believe the intent of the coordination and testing standards is to recognize the importance to the Bulk Electric System (BES) of all interconnected generators with a capacity greater than 20 MVA. Hence, perhaps interconnected generators of this size should be included in the BES.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Southern Company	Yes	R1, Part 1.1.1 needs clarification. We recommend this be revised to state, "Assuming initial steady state system conditions with the AVR in service, verify the limiters..." Reflect any changes in M1. R1, Part 1.1.2 needs clarification. We recommend this be revised to state, "Confirm the settings determined in Part 1.1.1 have been applied to the in-service equipment." Reflect any changes in M1. **The wording of R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) R1 is a five calendar year verification, b) R2 is a re-verification due to changes in the system, c) use of "equipment capabilities" throughout the standard, d) separating the components of the previous R1 paragraph into subparts R1.1 and R1.2 for clarification** Some consideration of changing the five year recurring verification of the coordination required by R2 to a six year period should be performed so that typical 18 month and 3 year outage schedules will coincide with the requirement periodicity. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity.**

Organization	Yes or No	Question 11 Comment
		In the applicability sections 5.1 and 5.2, we prefer that the percent complete be "of the entities total applicable MVA" rather than "of its applicable Facilities". **The SDT believes it would be more complex for entities to track percentage of MVA than number of units and will not make the requested change.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
PacifiCorp	Yes	1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of Section 4.2. - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for section 4.2.1): "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to section 4.2.2 and 4.2.3.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly. Section 4.2.2 already uses the words "directly connected", no change will be needed. Section 4.2.3 does not use the words "directly connected", however the words used are from the Statement of Compliance Registry Criteria part III.c.2. No change will be made.		
Exelon		1) In the Consideration of Comments on Generator Verification (PRC-019-1) - Project 2007-09 dated 2/22/12 (Question 5 on p 57), Exelon requested that the implementation period by 2 years following regulatory approval. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). An implementation period of 2 years will allow for any modifications to existing equipment be completed during a refueling outage.In response to Exelon's comments on Questions 5, the SDT states that "[t]he SDT does not believe the requirement to have 20 percent of

Organization	Yes or No	Question 11 Comment
		applicable units compliant within the first year is an undue burden. For the example noted, the unit could be verified with the last 20 percent of Exelon's fleet, which gives over four years to comply with the standard."Exelon does not believe that the SDT fully evaluated the example. Exelon Nuclear is registered with NERC in the RFC Region as a GO/GOP. This registration encompasses 16 generating units which are all nuclear generating units. Exelon Nuclear is also registered with NERC in the SERC Region as a GO/GOP. This registration encompasses only one (1) generating unit which is also a nuclear generating unit. Therefore the explanation given by the SDT to move the nuclear "unit" to the last 20 percent of the implementation period is impractical as it would be for any GO/GOP that has a fleet of all nuclear generating units. **Paragraphs 5.1.1 and 5.2.1 of the Effective Date section have been revised to two years in recognition of entities with few units that may have outage schedules that extend past one year.** 2) PRC-019-1 R1 (or the Applicability section of the Standard) should not apply to facilities currently in service until changes in the protection system are made. Applying this Standard to facilities in service will be a paperwork burden and will have no impact on reliability. It is more reasonable to apply PRC-019-1 R1 to facilities upon changes to the protection system. **The SDT disagrees that addressing miscoordination should be postponed until changes in a protection system are made. Such changes may not occur for decades. If it is determined that a protection system setting change is needed to address miscoordination, that is an easy task to accomplish during a scheduled outage.** 3) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). **The inclusion of synchronous condensers makes it necessary to clarify the applicability and restate the**

Organization	Yes or No	Question 11 Comment
		portions of the Statement of Compliance Registry Criteria that apply. 4) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted. **The SDT agrees with your suggestion. The first two paragraphs have been removed and the remaining wording has been slightly modified such that the Evidence Retention section matches other recently-approved standards.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Indiana Municipal Power Agency		1)In section 4.2. Facilities, IMPA recommends using Bulk Electric System instead of bulk power system. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** 2) IMPA believes that this standard does not increase the reliability of the Bulk Electric System and tends to be an expensive and administrative burden to smaller entities. In addition, IMPA does not see how this standard is a performance based standard which NERC determined to be the course of the future for reliability standards. IMPA believes that the industry does not need this standard. **The SDT believes there is a reliability benefit to having protection, limiters, and equipment capabilities properly coordinated. There is no need to recalculate all of the numbers every five years if the entity verifies that the settings and capabilities have not changed. It is possible that the SSSL may change without knowledge of the GO. It is prudent to ensure that coordination with that limit exists. The drafting of this standard began before NERC's Performance Based Standard initiative was initiated.** 3) IMPA does not understand why this needs to be performed once every five

Organization	Yes or No	Question 11 Comment
		years if none of the equipment has been changed. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Texas Reliability Entity		1)Purpose: Suggest replacing the phrase “equipment capabilities” with the NERC-defined term “Facility Ratings”. **The term “Facility Ratings” would imply that all of the equipment within the scope of FAC-008 would have to be evaluated for coordination under this standard. That is not the case. The SDT will not make the suggested change.** 2)R1.1.1: Suggest breaking this up to make the requirement clear.R1.1 Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility:1.1.1 Limiters and the Protection System for the applicable Facility are set to allow full capability within the Facility Ratings of the applicable Facility and steady-state Stability Limits;1.1.2 Limiters are set to operate before the Protection System of the applicable Facility;1.1.3 The Protection System of the applicable Facility is set to operate, isolate or de-energize equipment, in order to protect equipment from damage when operating conditions exceed Facility Ratings or Stability Limits;1.1.4 Settings determined in Parts 1.1.1 through 1.1.3

Organization	Yes or No	Question 11 Comment
		are applied to in-service equipment. **The wording of R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) R1 is a five calendar year verification, b) R2 is a re-verification due to changes in the system, c) use of "equipment capabilities" throughout the standard, d) separating the components of the previous R1 paragraph into subparts R1.1 and R1.2 for clarification** 3)R2: Remove the phrase "the existence of" in the first sentence. Recommend re-wording as follows "Each Generator Owner and Transmission Owner shall verify the coordination identified in Requirement R1.....". **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording has been changed to "perform the coordination…".** 4)R2: Suggest considering removal of the phrase "are expected to" as this is somewhat arbitrary and could lead to differences in application of the Standard. The VSL for R2 has the following phrase "identification or implementation of a change that affected the coordination" that indicates the GO or TO verified ONLY coordination on changes that affected the coordination (rather than what the Requirement states with the phrase "are expected to"). If the phrase "are expected to" is meant to bolster coordination efforts than the VSL language should address the same concept. **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.** 5)R2: Suggest re-wording three bullets as follows (leave 4th bullet unchanged): o Voltage regulating equipment settings or component changes o Generating or synchronous condenser Facility Rating changes o Generating or synchronous

Organization	Yes or No	Question 11 Comment
		condenser step-up transformer Facility Rating changes **The SDT agrees with your comment regarding the first bullet and has added "…settings or equipment changes." The SDT disagrees that Facility Ratings is the appropriate term to use with respect to changes in the rotating machine or transformer.** 6)M1: Suggest replacing the phrase "applicable Facility capabilities" with "applicable Facility Ratings". Also, suggest replacing the word "capabilities" with "Facility Ratings" in the 3rd bullet of M1. **The SDT disagrees that Facility Ratings is the correct term in this application. The Facility Rating could be determined by an element other than the generator that is not involved with the coordination activities described in this standard.** 7)VSL R1: Suggest rewording as follows to match the R1 requirement, "The Generator Owner or Transmission Owner failed to coordinate the voltage regulating controls and Protection System settings with the applicable Facility Ratings as specified in Requirement R1." **The SDT agrees and has made the suggested changes to the wording. Additional VSLs were added based on increments of tardiness.** 8)VSL Severe R2: Remove the phrase "the existence of" in both sentences. Recommend re-wording as follows "The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1….." **The SDT agrees and has made the suggested changes to the wording.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Wisconsin Electric Power Company		a. In Requirement R1.1.1 , the requirement to verify that Protection System devices are set to "operate before conditions cause damage to equipment" is not attainable and should be revised or eliminated. The best possible settings cannot guarantee that equipment will not be damaged. The best that can be expected is for protection settings to decrease the risk of damage, or to limit the extent of damage if it occurs. **The wording of R1 has been changed as suggested by many**

Organization	Yes or No	Question 11 Comment
		entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) R1 is a five calendar year verification, b) R2 is a re-verification due to changes in the system, c) use of "equipment capabilities" throughout the standard, d) separating the components of the previous R1 paragraph into subparts R1.1 and R1.2 for clarification b. In Requirement R1.1.2, the requirement to make sure that the limiters and protection settings are applied to in-service equipment is not necessary, and should be removed. It can be expected that professionals in the electric power industry are aware of the need to verify that the settings on in-service equipment are proper. Though errors may occur, this is an obvious aspect of good utility practice and responsible care of assets. Therefore, there is no need for a regulatory requirement. In fact no regulation is able to totally prevent human error. Measure M1 also requires a similar change in this regard. **The changes suggested here are also incorporated as described in the response to your comment a).** c. In Section F Associated Documents, better references would be the following IEEE Power System Relaying Committee documents: 1. "IEEE C37.102-2006 IEEE Guide for AC Generator Protection", and 2. "Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee. **The SDT thanks the commenter for the suggestion. The documents cited will be added to Section F in the standard**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Consolidated Edison Co. of NY, Inc.		o Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the NERC defined term.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has		

Organization	Yes or No	Question 11 Comment
modified the standard accordingly.		
PPL		Comments: a. Change “capabilities” in the third bull-dot under M1 to “ratings.” **The SDT disagrees that “ratings” is the correct term. A generator’s MVA rating does not fully describe its capabilities, since the actual MVA capability varies depending on the real power operating level. These capabilities are fully described the generator’s “Reactive Capability Curve” (a.k.a. “D-Curve”).** b. Having limits set before trips, and trips before damage, is a necessary part of the generation plant design process, so the requirements of the proposed standard in this respect are just business as usual. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in GO possession. We suggest that PRC-019 be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. **The SDT agrees that the coordination exercise should be performed as part of a new facility design or commissioning. However, the SDT has found that this is not always done, or may have not been done correctly. In addition, there are parameters that are affected by the transmission system (e.g. the SSSL) that may have changed and affected the original coordination.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
MRO NSRF		Facilities listed within 4.2, speak of generation units connected to the BPS. This difference of term does not provide consistency within this set proposed Standard. The BES Drafting Team has established a set of “inclusions” that will “pull in” generation units that may not be connected to the BES. Recommend that BES is used instead of BPS. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** Requiring an entity to verify the existence of coordination every five years as part of Requirement R2 is unnecessary. Rather than try to specify a review schedule, consider allowing entities to develop this schedule internally as a best

Organization	Yes or No	Question 11 Comment
		practice. If the drafting team were to retain this verification time frame, clarification should be included within the Requirement as to whether the five year verification resets itself following a change in coordination identified in R2. In consideration of these changes, recommend R2 be revised as follows: R2. “Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following:” **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Los Angeles Department of Water and Power		In regards to PRC-019-1, Attachment 1- Example of Capabilities, Limiters and Protection on aP-Q Diagram at nominal voltage and frequency, since different entities might have different standards in their Generator Protection System Standards for their generating units, it is not clear if they need to superimpose only some specific protection curves or if they are going to be expected to provide the curves for all the equipment protection wired into their generator protection systems. Additionally, some protection equipment from different OEM’s has time-dependent characteristics such as OELs. Since the reactive

Organization	Yes or No	Question 11 Comment
		capability curve represents steady-state limits, representing OEL characteristics on the RCC is not completely straightforward. When providing examples, have you consider the economic impact on implementing those examples?
Response: The GVSDT thanks you for your comment. The GO will be expected to provide the documentation/curves showing the coordination of all In-service equipment, both limiters and protection, wired into their generator protection systems and controls as stated in R1. In regards to representing time-dependent characteristics such as OELs, there are published technical papers on this subject, such as "Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee. The SDT has added some of these references to Section G of the standard.		
Luminant Energy Company LLC; Luminant Power		Luminant recommends in Requirement R1 that the coordination with Protection System be modified to reference the "applicable Protection System devices as referenced in Section G". As written, Protection System is all inclusive and would require verification of settings beyond the scope of this standard.
Response: The GVSDT thanks you for your comment. R1.1 identifies the scope to be the following "…the voltage regulating system controls, (including In-service 3 limiters and protection functions) with the applicable Facility capabilities and Protection System settings….". The intention of Section G is to provide some examples of evidence that will support a claim that the elements itemized in R1.1 are coordinated. Each of the elements appearing on the examples of Section G are either parts of the voltage regulating system controls, the Facility capabilities, or the generator Protection System. The wording "settings of the applicable Protection System devices as referenced in Section G" has been added to provide limits on the scope of the verification of settings covered in this standard.		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reason:(1) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Organization	Yes or No	Question 11 Comment
		to MOD-025, MOD-027 and PRC-019.
Response: The GVSDT thanks you for your comment. The SDT does not believe this standard requires unnecessary outages. It is an exercise in verifying protection and limiter settings and performing an engineering evaluation. To optimize the reliability benefits of this standard, the activities need to be performed prior to the reactive power capability test specified in MOD-025-1, so the implementation schedule for this standard is set by MOD-025.		
Seattle City Light		New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that Generator Owners will want to verify this coordination prior to performing the reactive capability testing required by MOD-025, which is also set on a five year periodicity. While there are triggers for the Generator Owner to update this coordination when equipment changes take place that will affect the coordination, the SDT believes this would be relatively infrequent. Changes in the transmission system, unknown to the Generator Owner, may affect the Steady State Stability Limit, so the Generator Owner will need to communicate with the Transmission Planner or Transmission Owner to determine if a change in the transmission system characteristics has occurred that would impact the coordination evaluation. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Ameren		Please clarify that R2 applies to Generating / synch condenser coordination as stated in A.3 in order to avoid confusion with the GO-TO Protection System coordination being addressed under Project 2007-06 and its proposed PRC-027-1. **The SDT agrees and has added the words "…with applicable Facilities…" in Requirement R2 similar to the wording in Requirement R1.**

Organization	Yes or No	Question 11 Comment
		(2) We believe that R2 is confusing as written. Please restate with subparts to clarify. Insert 'latter of' before 'identification or implementation' to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. For a given generator several changes may be identified at different times and then implemented during a common major overhaul or maintenance outage. A ten year periodic coordination review is sufficient if no other change has triggered a review; redoing a study more often than needed distracts valuable resources for other activities more important to BES reliability. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.** We propose:(R2) Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1:(2.1) At least once every ten years; or (2.2) Within 90 calendar days following the latter of identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following ... **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated**

Organization	Yes or No	Question 11 Comment
		into R1. (3) From our perspective High VRF is not justified. We suggest changing to Medium risk which in our opinion is a stretch for the following reasons. (3.1) PRC019 capability, limiters, and protection apply to a specific Element, one generator at a time, and if are not coordinated that single generator may be removed from service or may be damaged. But the loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures. If the generator trips because of loss of field, BES voltage state will actually improve. Furthermore, many generators have very few operating hours per year and pose little risk to the BES. High Risk requirement is not met.(3.2) PRC019 is not comparable to either PRC012 or PRC023. (3.2.1) Loss of a single generator differs from SPS in PRC-012 which trips more than one Element. (3.2.2) The vast majority of the generators under PRC019 have much less capability than the Elements under PRC-023 which are either >200kV or critical BES lines and transformers in PRC-023 which are major Elements. FERC Guideline 3 is not met.(3.3) In an emergency condition, lack of intended coordination could affect the electrical state if many generators tripped. This supports Medium not High for FERC Guideline 4. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.** (4) VSL is misaligned with respect to this standard Facilities and Implementation. (4.1) Please add a % of Facilities threshold in R1 to better match the risk to BES reliability. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. (4.1.1) For R1, we suggest thresholds of 5% of the entities Facilities for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe VSL.(4.2) For R2, please replace the time-based (days late) with % of MWh (or MVar-hours for synchronous condensers) during the period of violation to more properly account for aggregate impact.

Organization	Yes or No	Question 11 Comment
		For example, (4.2.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.'(4.2.2) Moderate VSL becomes '...more than 5% and less than 10%'(4.2.3) High VSL becomes '...more than 10% and less than 15%'(4.2.4) Severe VSL becomes '... more than 15%' **The SDT disagrees that structuring the VSL's by percentage of units missed is acceptable. The requirement calls for each unit to be coordinated. Missing one unit is a violation of the requirement.** (5) VRF and VSL need to be applied commensurate with BES reliability risk.(5.1) We believe that in this standard, VRF High and VSL Severe is not justified as drafted, and likely to lead to the unintended consequence of disabling limiters and protection to avoid compliance burden. (5.1.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.'(5.1.2) Moderate VSL becomes '...more than 5% and less than 10%'(5.1.3) High VSL becomes '...more than 10% and less than 15%'(5.1.4) Severe VSL becomes '... more than 15%' **The SDT agrees regarding the VRF. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk. The SDT disagrees that structuring the VSL's by percentage of units missed is acceptable. The requirement calls for each unit to be coordinated. Missing one unit is a violation of the requirement.** (6) Violation Severity Level R2: The increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Also in R2 you need a space between "5years". **The SDT has been informed by NERC that the standard increment is 10 days when the expectation for compliance is 90**

Organization	Yes or No	Question 11 Comment
		days. The SDT has corrected the missing space in "5years". (7) There is no mention of working with the Transmission Planner anywhere in the standard. The TP will be the entity that determines the Steady State Stability Limit. **Information about both the generator and the transmission system is necessary to calculate the SSSL (the formulas necessary to perform the calculation are shown in Section G, Reference). The SDT does not believe the Transmission Planner would be unwilling to provide the appropriate information.** (8) Please replace "Bulk Power System" with "Bulk Electric System" in numerous places. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** (9) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website. **The SDT agrees that this would be convenient. Unfortunately, copyright laws prohibit this.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Public Utility District No. 1 of Clark County		PRC-019 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60%, and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with PRC-019. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Response: The GVSDT thanks you for your comment. Paragraphs 5.1.1 and 5.2.1 of the Effective Date section have been revised to two years in recognition of entities with few units that may have outage schedules that extend past one year. The use of "at least" in each of the Effective Date subsections recognizes generator and transmission owners with a limited number of facilities.		

Organization	Yes or No	Question 11 Comment
FirstEnergy		R1 - The term "In-service" should not be capitalized
Response: The GVSDT thanks you for your comment. The change has been made as recommended.		
Independent Electricity System Operator		R1 VSL: There is only a SEVERE VSL assigned to Requirement R1, for the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1. This condition does not appear to be consistent with the intent of Requirement R1, which requires the responsible entities to coordinate the voltage regulating system controls, (including In-service limiters and protection functions) with the applicable Facility capabilities and Protection System settings. The parts that follow also prescribe the actions need for verification, not the identification of the existence of the verification information. **The SDT has restructured Requirement R1 to include the five year repetition of evaluating coordination and has restructured the VSL for this requirement accordingly. The words regarding "…existence of coordination…" have been removed.** Note that the SEVERC VSL for Requirement R2 includes the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years. This condition is almost identical to the SEVERE VSL for R1, except it has a time component associated with the failure. A failure to verify the existence of the coordination specified in Requirement R1 in more than 6 years, despite it might have implemented the verification exercise stipulated in R1, can subject an entity to being found non-compliant twice. We have a serious concern with this. **Requirement R2 has been restructured so that it only involves addressing changes to the settings or equipment that will affect coordination. The time frame is much different and the VSL's for Requirement R2 have been restructured accordingly.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		

Organization	Yes or No	Question 11 Comment
TransAlta Centralia Generation LLC		R2. Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, Please verify the reason for "at least once every five years". If the existing practice (such as 5 years testing in the WECC region) shows that for those generators without changing any associated equipment the models do not change more than 5 years, it is recommended the duration be longer than 5 years.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
ReliabilityFirst		ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. **The inclusion of synchronous condensers (which are not included in the SCRC) makes it necessary to clarify**

Organization	Yes or No	Question 11 Comment
		the applicability. b. ReliabilityFirst requests clarification on why the term "Bulk Power System" is used rather than "Bulk Electric System." ReliabilityFirst interprets, that by using the term "Bulk Power System", units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** 2. Requirement R2 a. ReliabilityFirst recommends removing the following language from Requirement R2: "that are expected to affect this coordination." The term "expected" is ambiguous and is hard to measure. **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle.** b. ReliabilityFirst recommends adding the phrase "with applicable Facilities" after the opening phase of, "Each Generator Owner and Transmission Owner." The addition of this language will be consistent with the language in Requirement R1. **The SDT agrees with your comment and has added the words as suggested.** 3. Measure M1 a. The language in Measure M1 is set up more like a requirement /RSAW rather than a Measure. Measures should be set up to provide identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Furthermore, the Measure should not introduce new concepts or requirements. ReliabilityFirst recommends the following for consideration: "Each Generator Owner and Transmission Owner with applicable Facilities will have evidence that it coordinated the voltage regulating system

Organization	Yes or No	Question 11 Comment
		with the applicable Facility capabilities and Protection System settings as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed." **The SDT agrees with your comment and has revised Measure M1.** 4. Reference Section a. ReliabilityFirst recommends removing the "Examples of Coordination" from the standard since they are simply guidance (as stated in the note - This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions). Examples would be more appropriately housed within an associated whitepaper, FAQ, guidance document, etc. and should not be housed within a NERC Reliability Standard. **The SDT wants to provide the auditor and the responsible entity with typical examples of evidence that demonstrate compliance with R1 and R2. There already exists in technical publications and textbooks many examples of what a coordinated Protection System looks like.** 5. VSLs and associated Requirements a. When timeframes are referenced within the VSLs (and associated Requirements), ReliabilityFirst recommends strictly using a month format (e.g. 60 months) instead of a year/month format. This would be consistent with various other NERC Reliability Standards. **The time interval specified for evaluation of the coordination (now in Requirement R1) is five calendar years. The SDT feels this gives the Generator Owners flexibility in achieving compliance while working with equipment outage schedules. The SDT feels that defining the interval in months would be more onerous to the Generator Owners with no improvement in grid reliability.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
SERC Planning Standards		The comments expressed herein represent a consensus of the views of the

Organization	Yes or No	Question 11 Comment
Subcommittee		above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
Response: The GVSDT thanks you for your comment. The SDT will observe the stated caveat.		
American Electric Power		The purpose statement as provided in the standard is not the same as the one stated in this comment form. **The SDT agrees and apologizes for the confusion. NERC staff revised the wording of the Purpose after the Comment Form was developed.** The VSL for R1 should be graduated. For example, missing one element on a fleet should not be categorized as a severe VSL. Perhaps a system similar to the one (Proposed?) for PRC-005 could be adopted. **The SDT has restructured Requirement R1 such that this requirement now defines the five year interval for evaluation of coordination. As such, the VSL for this requirement has also been restructured and now defines the severity levels in terms of tardiness.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Imperial Irrigation District (IID)		The standard is still difficult to read and determine the applicability to the reliability to the BES. For example, it could not be determined in a first, second, or third reading (with team discussion) whether the standard is suggesting we change the maintenance or operations setting by the manufacturer’s OEM.
Response: The GVSDT thanks you for your comment. The SDT apologizes that the commenter is confused about the intent. The SDT tried to provide some clarity by including examples of how to show coordination. Similar to protection coordination, this standard may require a protection setting or limiter setting to be adjusted if the evaluation indicates they are not properly coordinated. It is up to the equipment owner to determine which setting to change if miscoordination is observed.		
Entergy Services, Inc		There needs to be a requirement that the GO protection coordinate with the steady state stability limit. Entergy recommends inserting “or reach steady state

Organization	Yes or No	Question 11 Comment
		stability limits" after "equipment" in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions. **The wording of Requirement R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) Requirement R1 is a five calendar year verification, b) Requirement R2 is a re-verification due to changes in the system, c) the term "equipment capabilities" is now used consistently throughout the standard, d) the components of the previous Requirement R1 paragraph have been separated into subparts R1.1 and R1.2 for clarification. As suggested, R1 now explicitly states that protection needs to be coordinated with steady state stability limits and that the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions.** Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Entergy recommend that you stay with a 30 day increment. **The NERC guidelines for VSL's specify a 10 day increment when the expectation is that the activity be done within 90 days.** Also in R2 you need a space between "5years". **The SDT agrees and has made the correction as suggested.**
SERC Dynamic Review Subcommittee (DRS)		There needs to be a requirement that the GO protection coordinate with the steady state stability limit. We recommend inserting "or reach steady state stability limits" after "equipment" in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state

Organization	Yes or No	Question 11 Comment
		stability limits assuming normal AVR control loop and system steady state operating conditions. **The wording of Requirement R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) Requirement R1 is a five calendar year verification, b) Requirement R2 is a re-verification due to changes in the system, c) the term "equipment capabilities" is now used consistently throughout the standard, d) the components of the previous Requirement R1 paragraph have been separated into subparts R1.1 and R1.2 for clarification. As suggested, R1 now explicitly states that protection needs to be coordinated with steady state stability limits and that the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions.** Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? We recommend that you stay with a 30 day increment. **The NERC guidelines for VSL's specify a 10 day increment when the expectation is that the activity be done within 90 days.** Also in R2 you need a space between "5years". **The SDT agrees and has made the correction as suggested.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Northeast Power Coordinating Council		This Standard is written to verify coordination of generating unit Facility or synchronous voltage regulator controls, limit functions, equipment capabilities and Protection Systems. The Standard, as written, may apply to more generation than intended. The Standard as currently written protects the BPS and applies to generation units that are required to register with NERC in accordance with the Statement of Compliance Registry Criteria (SCRC). The approval of a new BES

Organization	Yes or No	Question 11 Comment
		definition by FERC will define new more limiting inclusion criteria than the (SCRC) for generators and therefore will change the population of generators material to the BES. The unintended consequence is that the current wording of the Standard protects the BPS not the BES and uses the SCRC for defining applicable generators, not the BES definition generator Inclusion Criteria. The Standard in its current form will apply to generators that will not be considered material to the BES and not necessary for the reliability of the Transmission System. Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the NERC defined term.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Ingleside Cogeneration LP		We believe that the project team has taken a positive step in R1.1.1 to establish that Protection Systems must operate before the generator or synchronous condenser sustains damage. This may actually be more sensitive than the SSSL - which is a good, but not perfect, proxy for the point at which components may be harmed. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of PRC-019-1, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		

Organization	Yes or No	Question 11 Comment
ACES Power Standards Collaborators		We do not believe Requirement R2 as written accomplishes the reliability purpose. Isn't the purpose of R2 to compel registered entities to re-verify coordination every five years along with changes to "systems, equipment or setting changes" within 90 days? We do not believe "shall verify the existence of coordination" accomplishes this. We believe that it only compels the registered entity to verify the coordination was performed at some point. It does not compel the entity to verify that coordination reflects current conditions such as Protection System settings. We suggest changing "shall verify the existence of coordination" to "shall coordinate". Furthermore, we think some of the confusion could be eliminated by including the five-year periodicity in Requirement R1 and focusing Requirement R2 on system and equipment changes. **The SDT agrees and has revised the wording in R2 to say "… shall perform the coordination…" The SDT has also moved the five calendar maximum repeat interval to R1 and R2 now deals with changes to the system that require re-verification of the coordination.** Section D.1.1 needs to be updated to reflect that latest approved language for the Compliance Enforcement Authority. **The SDT believes that "Regional Entity" is the proper Compliance Enforcement Authority.** The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the "verify the existence of the coordination" from Requirement R2. Requirement R1 uses "shall coordinate". **The SDT agrees and has revised the wording in the Severe VSL's for Requirement R1 to say "… failed to coordinate equipment capabilities, limiters, and protection…".** We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to

Organization	Yes or No	Question 11 Comment
		BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Public Service Enterprise Group (PSEG)		We have these additional comments: a. Regarding Blackstart Resources, the revision to R4, Part 4.2.4 would only apply to Blackstart Resources that are "material to and designated as part of a Transmission Operator's restoration plan." The Glossary definition of Blackstart Resources already requires them to be part of a Transmission Operator's restoration plan, so that language is redundant and should be removed. Our concern is the requirement that Blackstart Resources also be "material to a Transmission Operator's restoration plan." Who would judge a Blackstart Resource's materiality? The standard leaves this issue open, which is unacceptable. We suggest that Part 4.2.4 be rewritten as follows: "Any generator, regardless of size, that is a Blackstart Resource. **The wording in Part 4.2.4 comes directly from the NERC Statement of Compliance Registry Criteria. The SDT feels it is best to retain the NERC wording without modification.** b. Typo: in R1, "In-service" (not a Glossary term) should be "in-service." **The wording has been changed as recommended.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Tacoma Power		What if, during the Implementation Plan, it is discovered that coordination does

Organization	Yes or No	Question 11 Comment
		not exist, but the situation is resolved before the effective dates contained in the Implementation Plan? Would this constitute a violation of PRC-019-1? **The intent of the SDT is that the Generator Owner would address any miscoordination issues discovered during the initial evaluation. This would not be a violation of the standard as long as the evaluation were completed within the schedule outlined in Section 5, Effective Dates.** The Implementation Plan uses the phrase "...shall have verified..."R1.1.1 would require that "...the Protection System is set to operate before conditions cause damage to equipment..." Yet, the NOTE under Section G (Reference) states that "this standard does not require the installation or activation of any of the above limiter or protection functions." The latter statement could be construed (in the extreme case) to permit little or no protection functions, but this would appear to violate R1.1.1. Clarification is requested, as these two portions of the standard appear to conflict. **R1 contains the qualifier "in-service". This limits the applicability of this standard to only those elements that are chosen by the owner to be placed into service.** Under R2, is the 5-year interval (a) 5 calendar years or (b) closer to 1825 calendar days?R2 requires that entities "...verify the existence of the coordination identified in Requirement R1...within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following..." Protection System component changes is listed. If a component is replaced in-kind, is it actually required to verify the existence of the coordination identified in both Requirement R1.1.1 and R1.1.2, or just R1.1.2? Or, would this change be N/A to PRC-019-1 because it is not "...expected to affect this coordination..."? **The periodicity of five calendar years has been integrated into R1, and only "change" triggering events are now covered in R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a**

Organization	Yes or No	Question 11 Comment
		reevaluation prior to the scheduled five year cycle. Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity. **The terms "gross nameplate" and "gross aggregate nameplate" are used in the NERC Statement of Compliance Registry Criteria. While the terms are not in the NERC Glossary of Terms (and thus not capitalized in the standard), they are generally understood in industry to be the value indicated on the generator nameplate provided by the manufacturer.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Kansas City Power & Light		Applicability section states any generator regardless of size that is a black start resource. This standard should not be applicable to black start diesel generators. **The wording in Part 4.2.4 comes directly from the NERC Statement of Compliance Registry Criteria. The SDT feels it is best to retain the NERC wording without modification.** R2 requires verification every five years. This standard should only require initial verification during the five year implementation period. After the initial verification, no further verification should be required unless system or equipment changes dictate the need to make setting changes and re-verify. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this**

Organization	Yes or No	Question 11 Comment
		coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Oncor Electric Delivery Company		No
SERC Generation Subcommittee		No comment
Puget Sound Energy		None
Dynegy		No

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed (August 18, 2007).
5. First Draft of MOD-024-2 was posted for comment January 18 – February 18, 2010. MOD-024-2 was later combined with MOD-025-1 to form MOD-025-2.
6. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
7. Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 30-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop third version draft standard.	April - July 2012
2. Post response to comments and conduct successive ballot.	October-November 2012
3. Develop responses to ballot comments.	December 2012 – January 2013
4. Post responses to comments and conduct recirculation ballot.	February 2013
5. BOT adoption.	March 2013
6. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities:

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required[1]:

5.1.1

By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required[2]:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

[2] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

B. Requirements

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

C. Measures

M1. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R1.

M2. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, or dated information collected and used to complete attachments and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R2.

M3. Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing 1 to less than or equal to 33 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing more than 33 to 66 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data. OR	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner failed to verify the Real Power capability, per Attachment 1 of an applicable generating unit. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item

	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R2	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the Reactive	The Generator Owner verified and recorded the Reactive Power

	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did	Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72	capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR

	for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	calendar months but less than or equal to 75 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R3	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150	The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date

	within 120 calendar days, from the date the of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.	calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.	calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR	of the historical operating data that was selected for verification. OR The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit. OR The Transmission Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15calendar months.

	OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	

E. Regional Variances

None

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
Version 1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06
Version 2	TBD	Revised per SAR for Project 2007-09 and combined with MOD-024-1	TBD

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date.

It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below.

If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator, if applicable.

3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature
- Other data as applicable

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system interconnection transformer(s) tap setting.

3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary Load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.

4.2. If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.

Note 1: Under some transmission system conditions, the data points obtained by the Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The Mvar limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator.

Note 4: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

MOD-025 Attachment 2

<u>One-line Diagram, Table, and Summary for Verification Information Reporting</u>

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

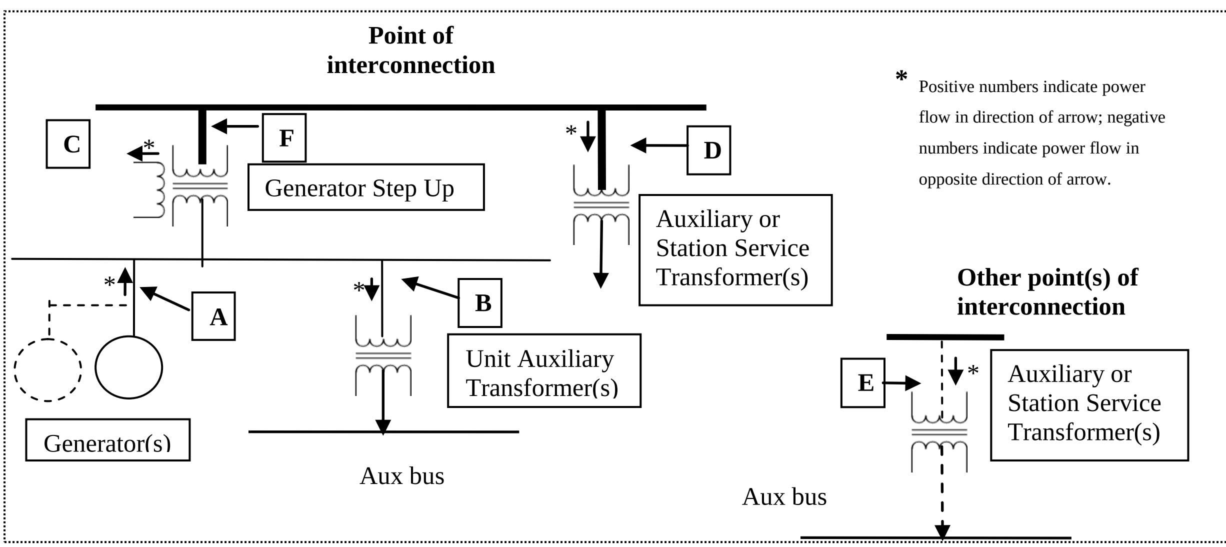
Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

<u>Check all that apply:</u>

- ☐ Over-excited Full Load Reactive Power Verification
- ☐ Under-excited Full Load Reactive Power Verification
- ☐ Over-excited Minimum Load Reactive Power Verification
- ☐ Under-excited Minimum Load Reactive Power Verification
- ☐ Real Power Verification
- ☐ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment

A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data)
Gross Reactive Power Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Voltage Ratio: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end of the verification period:

  Air temperature: _________

  Humidity: _________

  Cooling water temperature: _________

  Other data as applicable: _________

- The recorded Mvar values were adjusted to rated generator voltage, where applicable.
- Generator hydrogen pressure at time of test (if applicable) ______________

Date that data shown in last verification column in table above was taken _____________

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed (August 18, 2007).
5. First Draft of MOD-024-2 was posted for comment January 18 – February 18, 2010. MOD-024-2 was later combined with MOD-025-1 to form MOD-025-2.
6. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
7. ~~6.~~ Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.

Proposed Action Plan and Description of Current Draft:

This is the ~~second~~ third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a ~~45~~30-day concurrent formal comment period and ~~initial~~ successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. Develop responses to comments and develop second version draft standard.~~	~~July 2011 – February 2012~~
~~2. Post response to comments and conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.~~	~~March – April 2012~~
~~3~~1. Develop responses to ballot comments and develop third version of standard.	April – July ~~ne~~ 2012
2~~4~~. Post response to comments and conduct successive ballot.	~~June~~ October – November 2012
3~~5~~. Develop responses to ballot comments.	~~June – July~~December 2012 – January 2013
4~~6~~. Post responses to comments and conduct recirculation ballot.	~~August~~February 2013 ~~2012~~
5~~7~~. BOT adoption.	March 2013~~September~~

	~~2012~~
6~~8~~. File with regulatory authorities.	April 2013~~November 2012~~

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Owner ~~with~~ that owns synchronous condenser(s)

4.2. Facilities:

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the B~~b~~ulk Electric ~~power~~ S~~s~~ystem.

4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the ~~b~~Bulk Electric~~power~~ S~~s~~ystem.

4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the ~~b~~Bulk Electric~~power~~ S~~s~~ystem.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required[1]:

5.1.1 ~~By the first day of the first calendar quarter, one calendar year following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities~~.

By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required[2]:

~~**5.2.1** By the first day of the first calendar quarter, one calendar year following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.~~

~~5.2.2~~5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

~~5.2.3~~5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

~~5.2.4~~5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

~~5.2.5~~5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

~~**5.3.** Wind Farm Verification – If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site.~~

[2] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

B. Requirements

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R3. Each Transmission Owner shall provide its Transmission Planner with verification of the ~~Real~~ Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

C. Measures

M1. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information ~~and a correction for ambient conditions, if requested,~~ within 90 days to its Transmission Planner; such as dated electronic mail messages~~,~~ or mail receipts~~, or dated information collected and used to complete attachments,~~ in accordance with Requirement R1.

M2. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or~~,~~ mail receipts, ~~or dated information collected and used to complete attachments,~~ in accordance with Requirement R2.

M3. Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or~~,~~ mail receipts~~, or dated information collected and used to complete attachments,~~ in accordance with Requirement R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA. ~~Regional Entity~~

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the ~~latest~~ data or~~and~~ evidence to show compliance as identified below, ~~and the previous set of evidence if updated since the last compliance audit~~ unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete~~found compliant~~ or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, ~~from~~ of the ~~date of verification by staged test or the date of the historical operating data that was selected for verification.~~date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, ~~from~~ of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~of verification by staged test or the date of the historical operating data that was selected for verification~~. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was ~~missing~~ missing more	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days ~~from~~ of the date date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Generator Owner failed to verify the Real Power capability, per Attachment 1 of an applicable generating unit. OR

	but was missing 1 to less than or equal to 33 percent of the data. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or	than 33 to 66 percent of the data. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15~~2~~ calendar ~~months but less than or equal to 13 calendar~~ months.

	equal to 13 calendar months.			
R2	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the Reactive	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the Reactive Power	The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Generator Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months.

	The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15~~2~~ calendar months ~~but less than or equal to 13 calendar months~~.
R3	The Transmission Owner verified and recorded the Reactive Power capability	The Transmission Owner verified and recorded the Reactive Power capability of	The Transmission Owner verified and recorded the Reactive Power capability of	The Transmission Owner verified and recorded the Reactive Power capability of its applicable

	of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, from the date the of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Transmission~~Generator~~ Owner performed the Reactive Power verification per Attachment 1, "Periodicity for	its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Transmission ~~Generator~~ Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement)	an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Transmission ~~Generator~~ Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in	synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days from the date of verification by staged test or the date of the historical operating data that was selected for verification. OR The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit. OR The ~~Generator~~ Transmission Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Transmission ~~Generator~~ Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new

	conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Transmission ~~Generator~~ Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	but did so in more than 69 calendar months but less than or equal to 72 months. OR The Transmission ~~Generator~~ Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	more than 72 calendar months but less than or equal to 75 months. OR The Transmission ~~Generator~~ Owner performed the ~~v~~ Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15~~2 calendar months but less than or equal to 13~~ calendar months.

E. Regional Variances

None

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
Version 1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06
Version 2	TBD	Revised per SAR for Project 2007-09 and combined with MOD-024-1	TBD

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that ~~is expected to~~ affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date.

It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below. ~~If an applicable Facility is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes.~~

If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability

verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4~~5~~ below and b) the operational data demonstrates ~~is~~ at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and ~~,~~ Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour~~and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications~~.

~~2.1.1~~**2.1.2** Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all a~~A~~pplicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 A~~a~~t the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached~~. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output~~.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

~~2.1.2~~**2.2.3** Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

~~2.2. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour.~~

~~2.3. Collect the under-excited Reactive Power capability verification data identified in 2.1 and 2.2, and the over-excited Reactive Power capability verification data identified in 2.2 as soon as a limit is reached.~~

~~2.4.~~2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

~~2.5.~~2.4. Calculate ~~ollect~~ the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator, if applicable.

3.3. The voltage at the high and low side of the GSU and/or system ~~Interconnection~~ interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature
- Other data as applicable

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system ~~Interconnection~~ interconnection transformer(s) tap setting.

3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary Load(s), provide an engineering estimate and associated calculations. Transformer Real and

Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.

~~4.1.~~4.2. If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.

Note 1: Under some transmission system conditions, the data points obtained by the ~~MVAR~~ Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The M~~VAR~~var limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.~~Observe auxiliary bus voltage limits. The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner's database; nor is it likely this value will agree with data required to be submitted by MOD-010.~~

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal ~~MVAR~~ capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator.

Note 4: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

Check all that apply:

☐ Over-excited Full Load Reactive Power Verification

☐ Under-excited Full Load Reactive Power Verification

☐ Over-excited Minimum Load Reactive Power Verification

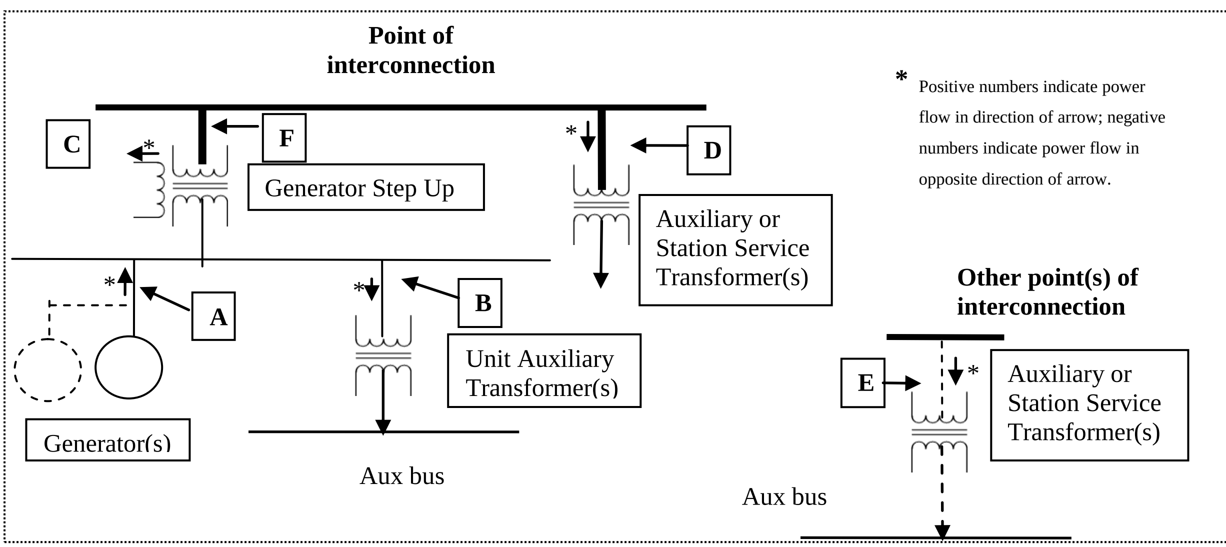
☐ Under-excited Minimum Load Reactive Power Verification

☐ Real Power Verification

☐ Staged Test Data

☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment

A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary t~~y~~ransformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data)
Gross Reactive Power ~~Generating~~ Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power ~~Generating~~ Capability (*MW)		~~N/A~~
Aux Real Power (*MW)		~~N/A~~
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		~~N/A~~
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Voltage Ratio~~Tap Settings~~: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end of the verification period:

  Air temperature: _________

  Humidity: _________

  Cooling water temperature: _________

  Other~~s~~ data as applicable: _________
- The recorded Mvar values were adjusted to rated generator voltage, where applicable.
- Generator hydrogen pressure at time of test (if applicable) _____________

Date that data shown in last verification column in table above was taken _____________

Remarks :

Note: If the verification value did not reach the t~~T~~hermal ~~C~~capability ~~C~~curve (D-~~C~~curve), describe the reason.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Approvals Required

MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner that owns synchronous condenser(s)

Facilities

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.

- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

In those jurisdictions where regulatory approval is not required:

- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20 percent of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20 percent annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

It is the intent of *ReliabilityFirst* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the *ReliabilityFirst* Reliability Standards Development Procedure will be followed for any such revisions or retirements.

Retirements

MOD-024-1 - Verification of Generator Gross and Net Real Power Capability and MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability should both be retired at midnight of the day immediately prior to the Effective Date of MOD-025-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Approvals Required

MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner ~~with~~ that owns synchronous condenser(s)
~~Generator Owner~~

Facilities

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the ~~b~~Bulk Electric~~power~~ ~~s~~System.
- Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the B~~b~~ulk Electric~~power~~ ~~s~~System.
- Generating plant/facility ~~>~~ greater than 75 MVA (gross aggregate nameplate rating) directly connected to the ~~b~~Bulk Electric~~power~~ ~~s~~System.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- ~~By the first day of the next calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable units.~~
- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

In those jurisdictions where regulatory approval is not required:

- ~~By the first day of the next calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable units.~~
- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20 percent of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20 percent annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

It is the intent of *ReliabilityFirst* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the *ReliabilityFirst* Reliability Standards Development Procedure will be followed for any such revisions or retirements.

Retirements

MOD-024-1 - Verification of Generator Gross and Net Real Power Capability and MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability should both be retired at midnight of the day immediately prior to the Effective Date of MOD-025-2 in the particular jurisdiction in which the new standard is becoming effective.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to ballot comments.	April - July 2012
2. Post response to comments and third version draft revision of standard for 30-day comment and successive ballot period.	October - November 2012
3. Develop responses to ballot comments.	December 2012 – January 2013
4. Post responses to comments and conduct recirculation ballot.	February 2013
5. BOT adoption.	March 2013
6. File with regulatory authorities.	April 2013

A. Introduction

1. Title: Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

2. Number: MOD-027-1

3. Purpose: To verify that the turbine/governor and load control or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

4. Applicability:

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an "applicable unit" that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.3 Generation the ERCOT Interconnection with the following characteristics:

[1] Turbine/governor and load control or active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

5. Effective Date:

5.1. For Requirements R1, and R3 through R6, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide one or more of the following to its requesting Generator Owner within 90 calendar days of receiving a written request: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of turbine/governor and load control or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation,

- Instructions on how to obtain the dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) models.

R2. Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA (gross nameplate rating) may be performed using either individual unit or plant aggregate model(s) or both. Each verification shall include the following:

2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response for either:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 Note 1 with the applicable unit on-line,
- A speed governor reference change with the applicable unit on-line, or
- A partial load rejection test,[2]

2.1.2. Type of governor and load control or active power control/frequency control equipment,

2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer),

2.1.4. Model structure and data for turbine/governor and load control or active power/frequency control, and

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or

[2] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply

nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit.

- Written notification, from its Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control or active power/frequency control model is not “usable,”
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[3] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[4]**Error! Bookmark not defined.** (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic[5]. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable; and shall include a technical description if the model is not usable that includes the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,

5.2. A no-disturbance simulation results in negligible transients, and

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[3] If verification is performed, the 10 year period as outlined in MOD-027 Attachment 1 is reset.

[4] Ibid.

[5] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping.

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instruction or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 180 calendar days of making changes.

M5. Evidence of Requirement R5 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and for a model that is not useable, a technical description is the model is not usable, and dated evidence of transmittal (e.g., electronic mail messages, postal receipts, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1; OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1; OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice; OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that altered the equipment response characteristic.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information;	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information; OR The Transmission Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information; OR The Transmission Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information; OR The Transmission Planner provided a written response without including confirmation of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control or active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307

2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005

3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004

4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004

5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004

6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

7) P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 10year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 2).
3	Applicable unit is not subjected to a frequency excursion per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit's real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit's real power response as expected.
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
5	Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location; AND Each applicable unit has the same MVA nameplate rating; AND The nameplate rating is ≤ 350 MVA; AND Each applicable unit has the same components and settings; AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
6	The Generator Owner has submitted a verification plan. (Requirement R3 or R4)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.
8	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10 calendar year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Unit model verification frequency excursion criteria:

- ≥ 0.05 hertz deviation (nadir point) from scheduled frequency for the Eastern Interconnection with the applicable unit operating in a frequency responsive mode
- ≥ 0.10 hertz deviation (nadir point) from scheduled frequency for the ERCOT and Western Interconnections with the applicable unit operating in a frequency responsive mode
- ≥ 0.15 hertz deviation (nadir point) from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode

NOTE 2: Establishing the recurring ten year unit verification period start date:

- The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 3: Consideration for early compliance:

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a 10 year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted~~.~~ (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.

Proposed Action Plan and Description of Current Draft:

This is the ~~second~~third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and ~~initial~~successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to ballot comments~~ and develop second version draft standard~~.	~~July 2011 – February~~April - July 2012
2. Post response to comments and ~~conduct a formal 45~~ third version draft revision of standard for 30-day comment ~~period with concurrent initial~~and successive ballot ~~for the revised standard~~period.	~~March – April~~October - November 2012
~~3. Develop responses to ballot comments.~~	~~April – June 2012~~
~~4. Post response to comments and conduct successive ballot.~~	~~June – July 2012~~
~~5~~3. Develop responses to ballot comments.	December~~August – September~~ 2012 – January 2013
~~6~~4. Post responses to comments and conduct recirculation ballot.	February 2013~~October 2012~~
~~7~~5. BOT adoption.	March 2013~~November~~

	~~2012~~
~~8~~6. File with regulatory authorities.	~~December 2012~~April 2013

A. Introduction

1. Title: Verification of Models and Data for Turbine/Governor and Load Control ~~and~~or Active Power/Frequency Control Functions

2. Number: MOD-027-1

3. Purpose: To verify that the turbine/governor and load control ~~and~~or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, ~~that~~ accurately represent generator unit real power response to system frequency variations.

4. Applicability:

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of ~~this standard,~~ the ~~term~~ requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an "applicable ~~Facility" is considered, "applicable units[2]." Units or plants with an average capacity[3] factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31,~~unit" that meet the following:

4.2.1 ~~Generating units connected to~~Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating~~) directly connected to the bulk power system.~~).

- ~~For each~~Individual generating plant ~~or generating Facility~~ consisting of ~~one or more~~multiple generating units that are directly connected ~~to the bulk power system~~ at a common BES bus with total generation greater than 100 MVA (gross aggregate ~~rating);~~

4.2.1.2 ~~Each individual generating unit greater than 20 MVA (gross~~ nameplate rating~~); and~~).

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[1] Turbine/governor and load control ~~and~~or active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants~~.~~).

~~2 Applicable generating units do not include startup or standby units not normally connected to the grid.~~

~~3 Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.~~

- ~~Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

4.2.2 ~~Generating units connected to~~Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating~~) directly connected to the bulk power system.~~).

~~For each~~**4.2.2.2** Individual generating plant ~~or generating Facility~~ consisting of ~~one or more~~ multiple generating units that are directly connected ~~to the bulk power system~~ at a common BES bus with total generation greater than 75 MVA (gross aggregate ~~rating):~~

~~Each individual generating unit greater than 20 MVA (gross~~ nameplate rating~~); and~~).

- ~~Each generating plant or generating Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

4.2.3 ~~Generating units connected to~~Generation the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating~~) directly connected to the bulk power system.~~).

4.2.3.2 ~~For each~~Individual generating plant ~~or generating Facility~~ consisting of ~~one or more~~ multiple generating units that are directly connected ~~to the bulk power system~~ at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating~~):~~).

- ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~

~~Each generating plant or generating Facility comprised of individual generating units less than 20 MVA (gross nameplate ratings)~~

5. Effective Date:

~~**5.1.** In those jurisdictions where regulatory approval is required:~~

~~**5.1.1** Each responsible entity shall ensure compliance with~~ For Requirements R1, and R3 through ~~R5 by~~R6, the first day of the first calendar quarter~~, three years following~~ beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval~~.~~

5.1. ~~Each Generator Owner~~ is not required, the standard shall ~~ensure at least 25 percent of its applicable units per Interconnection~~become effective on ~~an MVA basis are compliant with Requirement R2 by~~ the first day of the first calendar quarter~~, three~~ beyond the date this standard is approved by the NERC Board of

Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

~~5.1.2~~ For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval~~.~~

~~5.1.3 Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, five years following applicable regulatory approval.~~

~~5.1.4 Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following applicable regulatory approval.~~

~~5.1.5 Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following applicable regulatory approval.~~

5.2. ~~In~~, or in those jurisdictions where no regulatory approval is required~~:~~, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. ~~Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by~~ For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter~~, three~~ that is six years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty that is six years following NERC Board of Trustees adoption~~.~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

~~5.3.1 Each Generator Owner shall ensure at least 25~~For Requirement R2, 100 percent of ~~its~~the entity's applicable ~~units per~~unit gross MVA for each Interconnection on ~~an MVA basis are compliant with Requirement R2 by~~ the first day of the first calendar quarter~~, three~~ that is 10 years following ~~Board of Trustees adoption.~~

~~5.3.2 Each Generator Owner shall ensure at least 50 percent of its~~ applicable ~~units per Interconnection~~regulatory approval, or in those jurisdictions where no regulatory approval is required, on ~~an MVA basis are compliant with Requirement R2 by~~ the first day of the first calendar quarter~~, five~~ that is 10 years following NERC Board of Trustees adoption~~.~~

~~5.3.3 Each Generator Owner shall ensure at least 75 percent of its~~ or as otherwise made effective pursuant to the laws applicable ~~units per Interconnection on an MVA basis are compliant with Requirement R2 by~~

~~the first day of the first calendar quarter, seven years following Board of Trustees adoption.~~

5.4. ~~Each Generator Owner shall ensure at least 100 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, nine years following Board of Trustees adoption~~to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide one or more of the following ~~instructions and model data~~ to its requesting Generator Owner within 90 calendar days of receiving a written request ~~for those instructions or model data:~~: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of ~~acceptable~~ turbine/governor and load control ~~and~~or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation~~.~~,
- Instructions on how to obtain the ~~Transmission Planner's software manufacturer's~~ dynamic turbine/governor and load control ~~and~~or active power/frequency control ~~system~~function model library block diagrams and/or data sheets~~.~~ for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit ~~or plant~~ specific turbine/governor and load control ~~and~~or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) ~~model(s).~~models.

R2. Each Generator Owner shall provide, for each ~~of its~~ applicable unit~~s~~, a verified turbine/governor and load control ~~and~~or active power/frequency control model, including documentation and data (as specified in Part~~s~~ 2.1 ~~and 2.2,~~) to its Transmission Planner ~~(within 365 calendar days from the date that the response was recorded)~~ in accordance with the periodicity specified in MOD-027 Attachment 1~~, to ensure modeling data is accurate for use in simulation software.~~. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. ~~Perform verification~~ Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner ~~that~~. Verification of an individual unit rated less than 20 MVA (gross nameplate rating) may be performed using either individual unit or plant aggregate model(s) or both. Each verification shall include~~(s)~~ the following ~~information~~:

2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response ~~to the recorded response~~ for either ~~a~~:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 ~~Criteria~~Note 1 with the applicable unit on-line, ~~a~~

- A speed governor reference change with the applicable unit on-line, or ~~from a~~
- A partial load rejection test[4] ~~.~~,[5]

~~2.1.1.~~2.1.2. Type of governor and load control ~~and~~or active power control/frequency control equipment~~.~~,

~~2.1.2.~~2.1.3. A description of the turbine (e.g. for ~~H~~hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer~~).~~),

~~2.1.3.~~2.1.4. Model structure and data for turbine/governor and load control ~~and~~or active power/frequency control~~.~~, and

~~2.1.4.~~2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

~~2.2. For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA, perform verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5~~

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit. ~~The written response shall contain either the technical basis for maintaining the current model, or the model changes, or a plan to perform model verification[6] (in accordance with Requirement R2): *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*~~

- Written notification, from its Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control ~~and~~or active power/frequency control model is not "usable~~", or~~,"

[4] ~~Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on load data under the normal operating conditions under which the model is expected to apply~~

[5] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply

[6] ~~If verification is performed, the 10 year period as outlined in Attachment 1 is reset.~~

- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control ~~and~~or active power/frequency control model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the ~~predicted~~simulated turbine/governor and load control ~~and~~or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[7] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[8~~6~~] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control ~~and~~or active power/frequency control system that alter the equipment response characteristic[9]. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the turbine/governor and load control ~~and~~or active power/frequency control system verified model information ~~whether~~in accordance with Requirement R2 that the model is us~~e~~able (meets the criteria specified in Parts 5.1 through 5.3) or is not usable; and shall include a technical description if the model is not ~~useable.~~usable that includes the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The turbine/governor and load control ~~and~~or active power/frequency control function model initializes to compute modeling data without error~~.~~,

5.2. A no-disturbance simulation results in negligible transients~~.~~, and

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control ~~and~~or active power/frequency control model exhibiting positive damping.

C. Measures

M1. ~~Evidence for Requirement R1~~The Transmission Planner must ~~include~~have and provide the ~~transmitted~~dated request for instructions or data ~~and~~ , the transmitted instruction or data, and dated evidence of ~~transmission of requested instructions and data, such as dated~~a written transmittal (e.g., electronic mail ~~messages, dated~~ message, postal

[7] If verification is performed, the 10 year period as outlined in MOD-027 Attachment 1 is reset.

[8] Ibid.

[9] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

~~receipts, dated~~ receipt, or confirmation of facsimile ~~transmission~~) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. ~~Evidence for Requirement R2 must include, for~~ The Generator Owner must have and provide dated evidence it verified each ~~of the Generator Owner's applicable Facilities, the verification report showing that the~~ generator turbine/governor and load control ~~and~~or active power/frequency control model ~~was verified~~according to Part 2.1 for each applicable unit and ~~dated evidence of transmission, ,such as~~ a dated transmittal (e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmission~~) as ~~specified~~evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal~~, such as a dated~~ (e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmission.~~) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's ~~Facilities~~applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal~~, such as dated~~ (e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmittal~~) within 180 calendar days of making changes.

M5. Evidence of Requirement R5 must include, for each model received, the dated response ~~containing~~indicating the ~~information required~~model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and for a model that is not useable, a technical description is the model is not usable, and dated evidence of transmittal~~, such as dated~~ (e.g., electronic mail messages, ~~dated~~ postal receipts, or ~~dated~~ confirmation of facsimile ~~transmittal.~~) that the Generator Owner was notified within 90 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity~~

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest ~~and previous~~ turbine/governor and load control ~~and~~or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within ~~181~~180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to ~~30~~90 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than ~~30~~90 calendar days but less than or equal to ~~60~~180 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1~~.~~; OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than ~~60~~180 calendar days but less than or equal to ~~90~~270 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1~~.~~; OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified ~~turbine/governor and load control and active power/frequency control~~ model(s) more than ~~90~~270 calendar days late ~~or failed to provide the verified model(s)~~ to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1~~.~~; OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, ~~Subp~~Part 2.1~~.~~; OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice. ~~(R3)~~	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice. ~~(R3)~~	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice. ~~(R3)~~	The Generator Owner failed to provide a written response within ~~181~~180 calendar days of receiving written notice ~~as specified in Requirement R3.~~; OR ~~The Generator Owner's written response was provided within 181 calendar days of receiving written notice. However the~~The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and load control ~~and~~or active power/frequency control system that alter the equipment response characteristic. ~~(R4)~~	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and load control ~~and~~or active power/frequency control system that alter the equipment response characteristic. ~~(R4)~~	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and load control ~~and~~or active power/frequency control system that alter the equipment response characteristic. ~~(R4)~~	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within ~~271~~270 calendar days of making changes to the turbine/governor and load control ~~and~~or active power/frequency control system that altered the equipment response characteristic ~~as specified in Requirement R3~~.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable, ~~(~~including a technical description if the model is not useable~~)~~, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information~~. (R5)~~;	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable, ~~(~~including a technical description if the model is not useable~~)~~, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information~~. (R5)~~; OR The Transmission ~~Planner provided a written response within 181 calendar days to the Generator Owner however the~~Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable, ~~(~~including a technical description if the model is not useable~~)~~, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information~~. (R5)~~; OR The Transmission ~~Planner provided a written response within 181 calendar days to the Generator Owner however the~~Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner failed to provide a written response to the Generator Owner within ~~181~~180 calendar days of receiving the verified model information~~ as specified in Requirement R5.~~; OR The Transmission Planner provided a written response without including confirmation of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control ~~and~~or active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307

2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005

3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004

4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004

5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004

6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

7) P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

~~MOD-027 Attachment 1~~

~~Turbine/Governor and Load Control and Active Power/Frequency Control Model Periodicity~~

~~Periodicity Determination Supporting Criteria~~MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 10year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 2).
3	Applicable unit is not subjected to a frequency excursion per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit's real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit's real power response as expected.

~~Periodicity Determination Supporting Criteria~~MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.
5	Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location; AND Each applicable unit has the same MVA nameplate rating; AND The nameplate rating is ≤ 350 MVA; AND Each applicable unit has the same components and settings; AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
6	The Generator Owner has submitted a verification plan. (Requirement R3 or R4)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

~~Periodicity Determination Supporting Criteria~~MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.
8	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10 calendar year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

~~Periodicity Determination Supporting Criteria~~MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action

~~Criteria~~NOTES:

NOTE **1:** Unit ~~**Model Verification Frequency Excursion Criteria**~~model verification frequency excursion criteria:

- ≥ 0.05 hertz deviation (nadir point) from scheduled frequency for the Eastern Interconnection with the applicable unit operating in a frequency responsive mode
- ≥ 0.10 hertz deviation (nadir point) from scheduled frequency for the ERCOT and Western Interconnections with the applicable unit operating in a frequency responsive mode
- ≥ 0.15 hertz deviation (nadir point) from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode

~~**Criteria**~~NOTE **2:** Establishing the ~~**Initial Ten Year Unit Verification Period Start Date:**~~

~~**For each applicable**~~recurring ten year unit~~**, the initial**~~ verification period start date ~~**is set to either of the 25 percent, 50 percent, 75 percent, or 100 percent Standard Implementation Effective Dates established for compliance in accordance with the nine calendar year transition period.**~~

~~**Criteria 3: Establishing the Recurring Ten Year Unit Verification Period Start Date**~~:

- The start date is the actual ~~**data collection date**~~ date of submittal of a verified model to the Transmission Planner for the most recently performed ~~**applicable**~~ unit verification.

~~**Criteria 4: For the purpose of calculating the initial ten year unit verification period 25 percent, 50 percent, 75 percent or 100 percent threshold for generation fleet compliance, equivalent unit MVA is included (reference 4th row in the following table).**~~

NOTE 3: Consideration for ~~**Early Compliance**~~early compliance:

Existing turbine/governor and load control ~~**and**~~or active power/frequency control model verification is sufficient for demonstrating compliance for a ~~**ten**~~10 year period from the actual ~~**verification**~~transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification~~.~~
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard~~.~~

~~Event Triggering Verification~~	~~Verification Periodicity~~	~~Comments~~
~~Establishing the initial verification period (Criteria 2) for an applicable unit (Requirement R2)~~	~~Record unit Real Power response to the first frequency excursion event that meets Criteria 1 on or after the Standard Implementation Effective Date.~~ ~~OR~~ ~~Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test before or on the Standard Implementation Effective Date~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.~~ ~~Criteria 4 applies when calculating generation fleet compliance during the 9-year transition period~~
~~Subsequent verification for an existing applicable unit~~	~~Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit's ten year anniversary date of the collection of the recorded unit Real Power response used for the current validation.~~ ~~OR~~ ~~Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test on or before the applicable unit's ten year anniversary date of the collection of the recorded unit Real Power response used for the current validation.~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.~~
~~Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed with settings final~~	~~Record unit Real Power response to the first frequency excursion event that meets Criteria 1~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that~~

~~Event Triggering Verification~~	~~Verification Periodicity~~	~~Comments~~
~~(Requirement R2)~~	~~OR~~ ~~Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the commissioning date~~	~~the response was recorded.~~
~~Existing applicable unit that is equivalent to another operating unit(s) at the same physical location~~ ~~AND~~ ~~Each equivalent applicable unit has the same MVA nameplate rating.~~ ~~AND~~ ~~The nameplate rating is ≤ 350 MVA.~~ ~~AND~~ ~~Each equivalent applicable unit has identical applicable components and settings.~~ ~~AND~~ ~~The model for one of these equivalent applicable units has been verified.~~ ~~(Requirement R2)~~	~~Verify a different equivalent unit during each ten year verification period.~~	~~Document circumstance with a written statement and include with the verified model and documentation and data provided to the Transmission Provider for the verified equivalent unit.~~ ~~Criteria 4 applies when calculating generation fleet compliance during the 9-year transition period.~~
~~Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period~~ ~~AND~~ ~~Neither an on-line speed governor reference test nor a partial load rejection test was performed.~~ ~~(Requirement R2)~~	~~Record unit Real Power response to the first frequency excursion event that meets Criteria 1after the ten year verification period~~	~~Document circumstance with a written statement.~~ ~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.~~

~~Event Triggering Verification~~	~~Verification Periodicity~~	~~Comments~~
~~Existing applicable unit control system response is altered resulting in an alteration of the response of the turbine/governor and load control or active power/frequency control model~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan.~~ ~~(Requirement R4)~~	~~Record unit Real Power response to the first frequency excursion event that meets Criteria 1.~~ ~~OR~~ ~~Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan.~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.~~
~~The Generator Owner receives written comments including dated electronic or hard copy evidence indicating that the recorded turbine/governor and load control or active power/frequency control response for three or more transmission system events did not match the predicted control system model response.~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan.~~ ~~(Requirement R3)~~	~~Record unit Real Power response to the first frequency excursion event that meets Criteria 1.~~ ~~OR~~ ~~Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the unit Real Power response was provided as part of the dated evidence.~~
~~The Generator Owner receives written comments detailing technical concerns with the Generator Owner's turbine/governor and load control and active power/frequency control model verification documentation.~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan~~ ~~(Requirement R3)~~	~~Record unit Real Power response to the first frequency excursion event that meets Criteria 1.~~ ~~OR~~ ~~Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date of the submitted verification plan~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.~~

~~Event Triggering Verification~~	~~Verification Periodicity~~	~~Comments~~
~~The Turbine/governor and load control and active power/frequency control model identified as unusable by the Transmission Planner.~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan.~~ ~~(Requirement R3)~~	~~Record unit Real Power response to the first frequency excursion event that meets Criteria 1.~~ ~~OR~~ ~~Record unit Real Power response for an on-line speed governor reference change test or a partial load rejection test no more than 365 calendar days from the date that of the submitted verification plan~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.~~
~~New or existing applicable unit is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)~~ ~~OR~~ ~~New or existing applicable unit has a disabled control system~~	~~Not required until responsive control mode operation for connected operations is established.~~	~~Document circumstance with a written statement.~~ ~~Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) once responsive control mode operation for connected operations is established.~~
~~New or existing applicable unit does not have an installed control system~~	~~Not required until unit has an installed control system~~	~~Document circumstance with a written statement.~~ ~~Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) once responsive control mode operation for connected operations is established.~~

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following applicable regulatory approval.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following applicable regulatory approval.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.

- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the ~~term~~ following ~~“applicable~~ Facilities ~~y” is~~ are considered, “applicable units~~[1]~~.” Units or plants ~~with an average capacity[2] factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31,~~ that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.

~~1 Applicable generating units do not include startup or standby units not normally connected to the grid.~~

~~2 Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.~~

- ~~For e~~Each generating plant or generating Facility consisting of ~~one or more~~multiple units that are connected to the ~~bulk power system~~Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).~~:~~
  - ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~
  - ~~Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.
- ~~For e~~Each generating plant or generating Facility consisting of ~~one or more~~multiple units that are connected to the ~~bulk power system~~Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~
  - ~~Each generating plant or generating Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.
- ~~For e~~Each generating plant or generating Facility consisting of ~~one or more~~multiple units that are connected to the ~~bulk power system~~Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~
  - ~~Each generating plant or generating Facility comprised of individual generating units less than 20 MVA (gross nameplate ratings)~~

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter~~, three years~~ following applicable regulatory approval.
- Each Generator Owner shall ensure at least 30~~25~~ percent of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, four ~~three~~ years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, ~~five~~ six years following applicable regulatory approval.
- ~~Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following applicable regulatory approval.~~
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, 10~~nine~~ years following applicable regulatory approval.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter~~, three years~~ following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30~~25~~ percent of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, four~~three~~ years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, six~~five~~ years following Board of Trustees adoption.
- ~~Each Generator Owner shall ensure at least 75 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, seven years following Board of Trustees adoption.~~
- Each Generator Owner shall ensure at least 100 percent of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, 10~~nine~~ years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Draft 2 of PRC-019-1 was posted for a 45 day concurrent comment and ballot period from February 29 – April 16, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 30-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop third version draft standard.	April - July 2012
2. Post response to comments and conduct successive ballot.	October-November 2012
3. Develop responses to ballot comments.	December 2012 – January 2013
4. Post responses to comments and conduct recirculation ballot.	February 2013
5. BOT adoption.	March 2013
6. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-1

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service [1] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate, isolate or de-energize equipment, in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1, These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes
- Protection System settings or component changes
- Generating or synchronous condenser equipment capability changes, or

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service [2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination review required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that

	implementation of a change in equipment or settings that affected the coordination.	implementation of a change in equipment or settings that affected the coordination.	implementation of a change in equipment or settings that affected the coordination.	affected the coordination.

E. Regional Variances

None.

F. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,”Protective Relaying For Power Generation Systems”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

“Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

“IEEE C37.102-2006 IEEE Guide for AC Generator Protection”

Version History

Version	Date	Action	Change Tracking

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.
- Converter over-temperature limiter and associated protection function.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

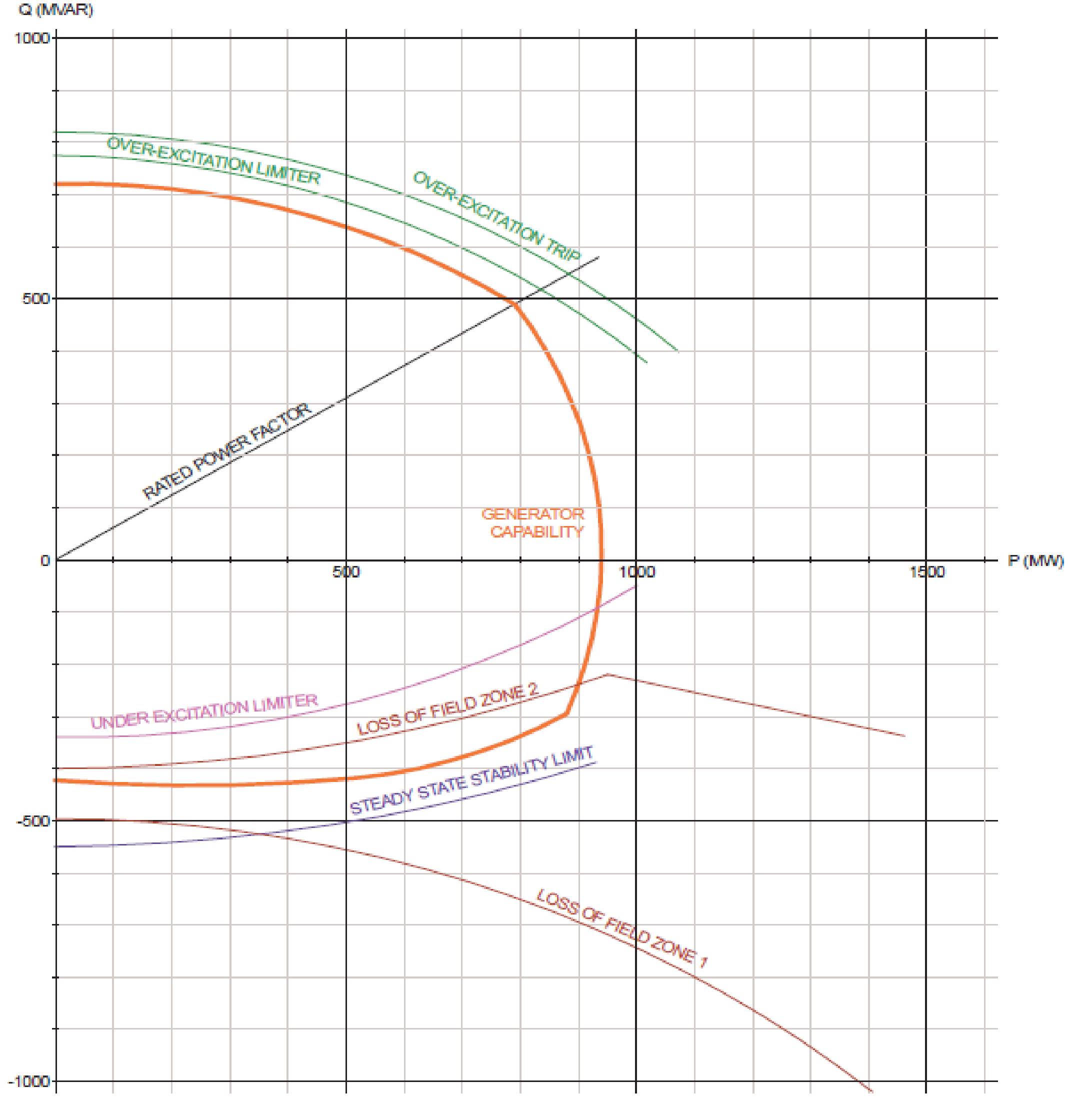
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

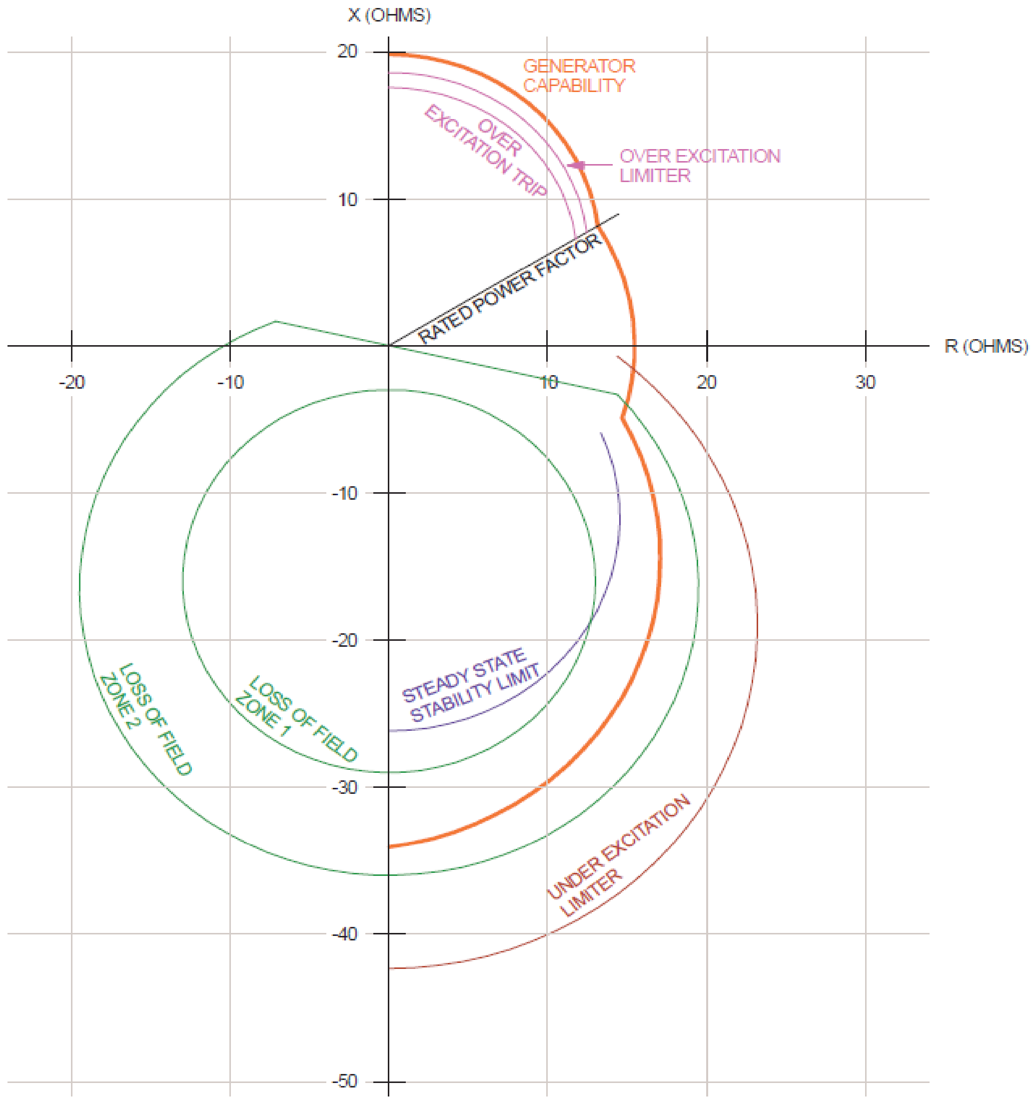
$C = (X_d - X_s)/2$

$R = (X_d + X_s)/2$

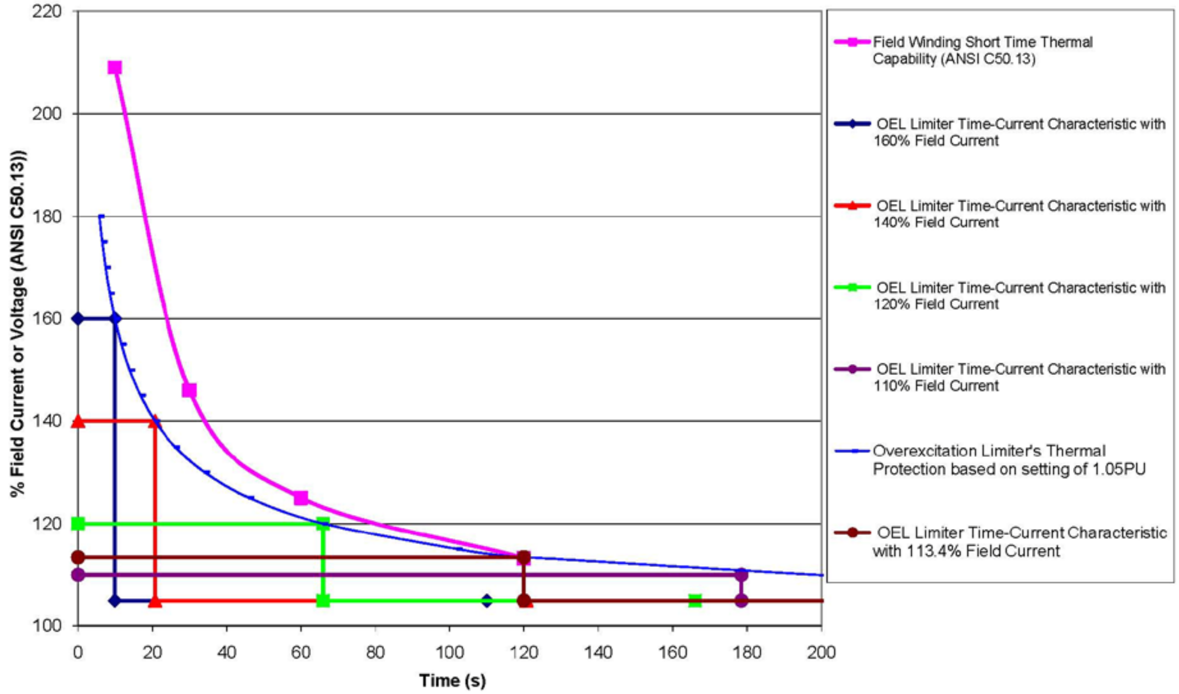
Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Draft 2 of PRC-019-1 was posted for a 45 day concurrent comment and ballot period from February 29 – April 16, 2012.

Proposed Action Plan and Description of Current Draft:

This is the ~~second~~ third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a ~~45~~30-day concurrent formal comment period and successive~~initial~~ ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop ~~second~~ third version draft standard.	April - July ~~2011 – February~~ 2012
~~2. Post response to comments and conduct a formal 45 day comment period with concurrent initial ballot for the revised standard.~~	~~February - March 2012~~
~~3. Develop responses to ballot comments.~~	~~March - June 2012~~
4. Post response to comments and conduct successive ballot.	~~June~~October-November 2012
5. Develop responses to ballot comments.	~~June – July~~December 2012 – January 2013
6. Post responses to comments and conduct recirculation ballot.	~~August~~ February 201~~2~~3
7. BOT adoption.	March ~~September~~ 201~~2~~3
8. File with regulatory authorities.	April ~~November~~ 201~~2~~3

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-1

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.

4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.

4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the ~~bulk power system~~Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 Any generator, regardless of size, that is a ~~Blackstart Resource~~blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

~~**5.1.1** By the first day of the first calendar quarter, one calendar year following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.~~

~~5.1.2~~5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

~~5.1.3~~5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

~~5.1.4~~5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

~~5.1.5~~5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

~~5.2.1 By the first day of the first calendar quarter, one calendar year following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.~~

~~5.2.2~~5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

~~5.2.3~~5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

~~5.2.4~~5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

~~5.2.5~~5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

B. Requirements

R1. ~~Each~~At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including ~~In~~in-service [1] limiters and protection functions) with the applicable ~~Facility~~equipment capabilities and settings of the applicable Protection System ~~settings.~~ devices and functions. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Long-term Planning]*

~~1.1. This coordination requires the following steps:~~

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.1. ~~Verify the~~ Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System ~~and~~of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

~~**1.1.1.**~~**1.1.2.** The applicable in-service Protection System ~~is~~devices are set to operate ~~before conditions cause~~, isolate or de-energize equipment, in order to limit the extent of damage ~~to equipment assuming normal AVR control loop and system steady state~~when operating conditions exceed equipment capabilities or stability limits.

~~**1.1.2.** Check the settings determined in Part 1.1.1 are applied to the in-service equipment.~~

R2. ~~Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within~~Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that ~~are expected to~~will affect ~~this~~the coordination~~, including but~~ described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1, These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes
- Protection System settings or component changes
- Generating or synchronous condenser equipment capability changes, or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

~~**M1.**~~ Each Generator Owner and Transmission Owner with applicable Facilities will have evidence~~,~~ (such as ~~example evidence~~ examples provided in PRC-019 Section G~~, to show~~) that ~~its applicable Facility~~ it coordinated the voltage regulating system controls, including in-service [2] limiters and ~~Protection System~~protection functions ~~are coordinated~~, with the applicable ~~Facility~~equipment capabilities and settings of the applicable Protection System ~~settings~~ devices and functions as specified in Requirement R1. ~~As applicable, this may include the following:~~

- ~~In service excitation system and voltage regulating system control, limiters and protection functions~~
- ~~In-service generator or synchronous condenser protection system settings~~
- ~~Generator or synchronous condenser capabilities, or~~

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

- ~~Steady state stability limit.~~

M1. ~~The coordination~~ This evidence should include ~~1) verifying the in-service limiters are set to operate before the protection and the protection is set to operate before conditions cause damage to equipment assuming normal AVR control loop and system steady state operating conditions, and 2) verifying the desired settings are applied to the in-service equipment.~~dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination review required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 ~~are~~ have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~Regional Entity~~

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

~~Each Generator Owner and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, ~~it~~the entity shall keep information related to the non-compliance until mitigation is complete and approved ~~found compliant~~ or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit ~~records~~report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~N/A~~ The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	~~N/A~~ The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	~~N/A~~The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to ~~verify the existence of the coordination~~coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner ~~verified the coordination~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. ~~OR~~	The Generator Owner or Transmission Owner ~~verified the coordination~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. ~~OR~~	The Generator Owner or Transmission Owner ~~verified the coordination~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. ~~OR~~	The Generator Owner or Transmission Owner failed to ~~verify the existence of the coordination~~coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within ~~121~~120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. ~~OR~~

	~~The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years but less than or equal to 5 years and 4 months.~~	~~The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years and 4 months but less than or equal to 5 years and 8 months.~~	~~The Generator Owner or Transmission Owner verified the coordination specified in Requirement R1 more than 5years and 8 months but less than or equal to 6 years.~~	~~The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years.~~

E. Regional Variances

None.

F. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

~~Reimert, Donald, ~~,”Protective Relaying For Power Generation Systems~~,~~”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

“Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

“IEEE C37.102-2006 IEEE Guide for AC Generator Protection”

Version History

Version	Date	Action	Change Tracking

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of~~-~~:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.
- Converter over-temperature limiter and associated protection function.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For ~~the coordination required by~~ this ~~standard~~example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

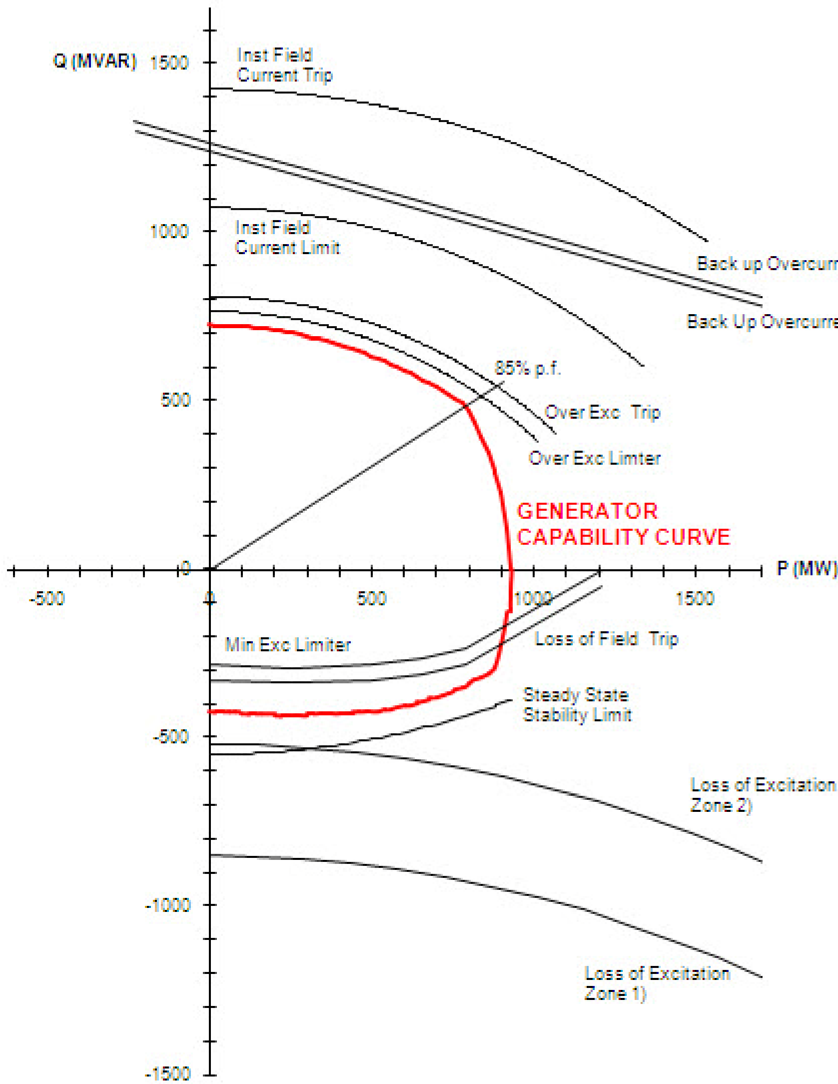
$$C = V^2_g/2*(1/X_s-1/X_d)$$
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

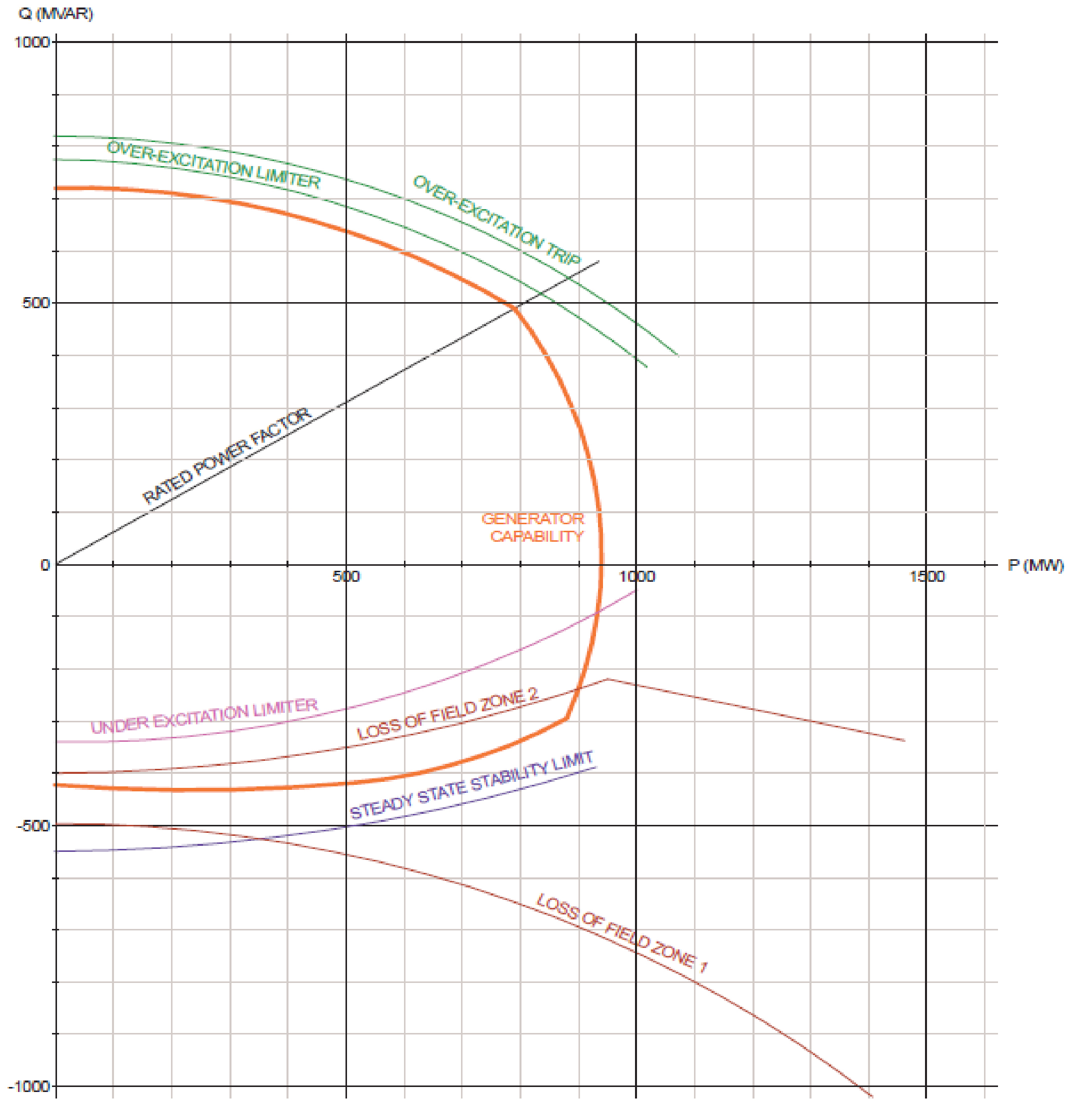
$$C = (X_d - X_s)/2$$

$$R = (X_d + X_s)/2$$

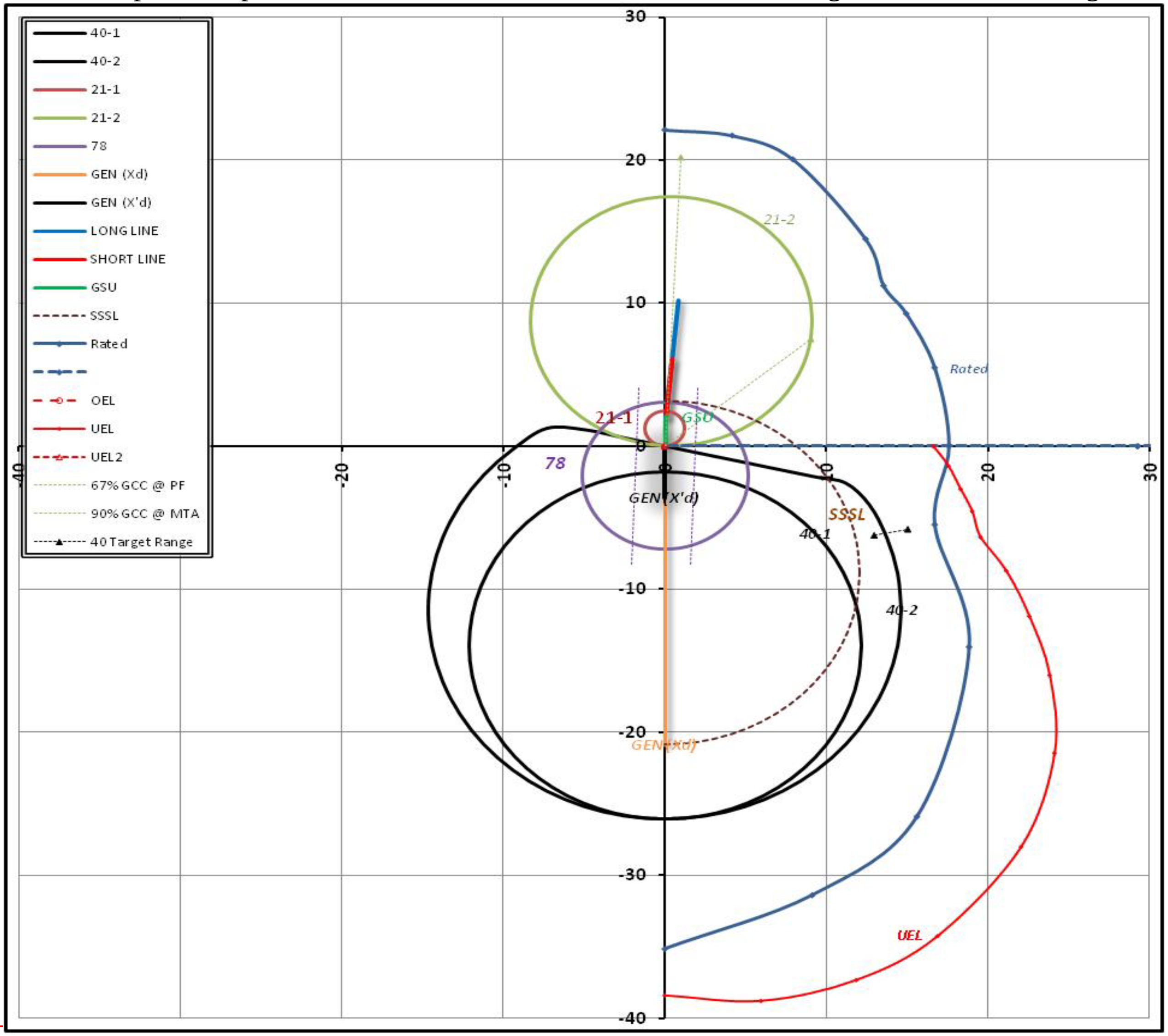
Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency

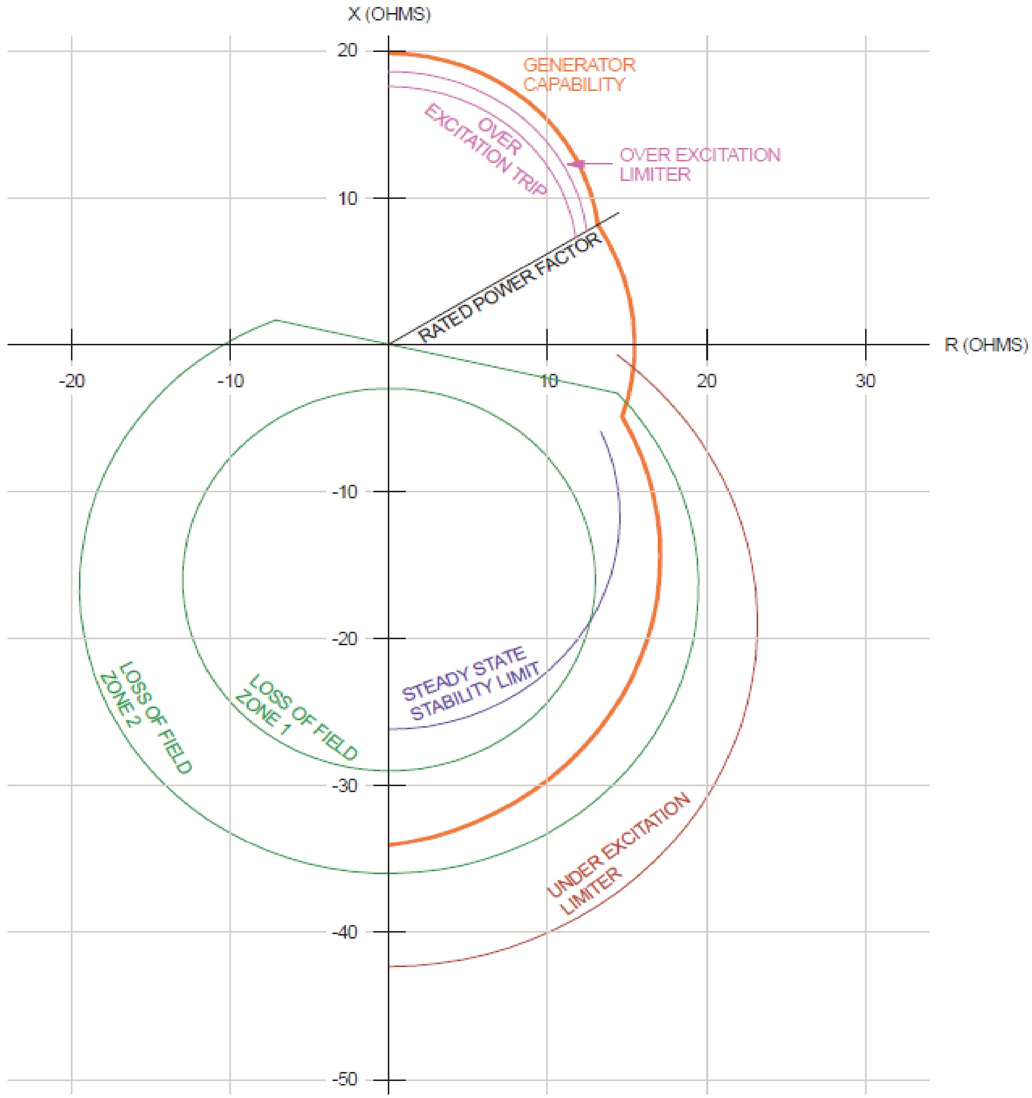


Example of Generator Capability Curve with Protection Elements Visible

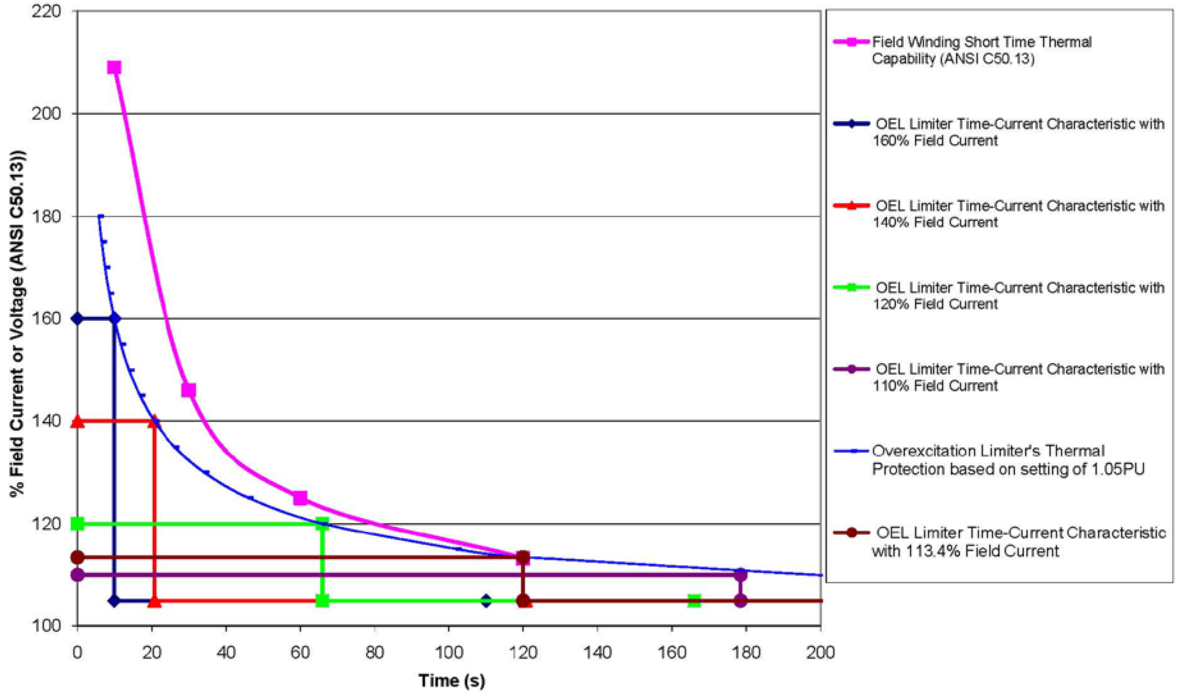

Q (MVAR)
1000
500
0
-500
-1000
500
1000
1500
P (MW)
OVER-EXCITATION LIMITER
OVER-EXCITATION TRIP
RATED POWER FACTOR
GENERATOR CAPABILITY
UNDER EXCITATION LIMITER
LOSS OF FIELD ZONE 2
STEADY STATE STABILITY LIMIT
LOSS OF FIELD ZONE 1

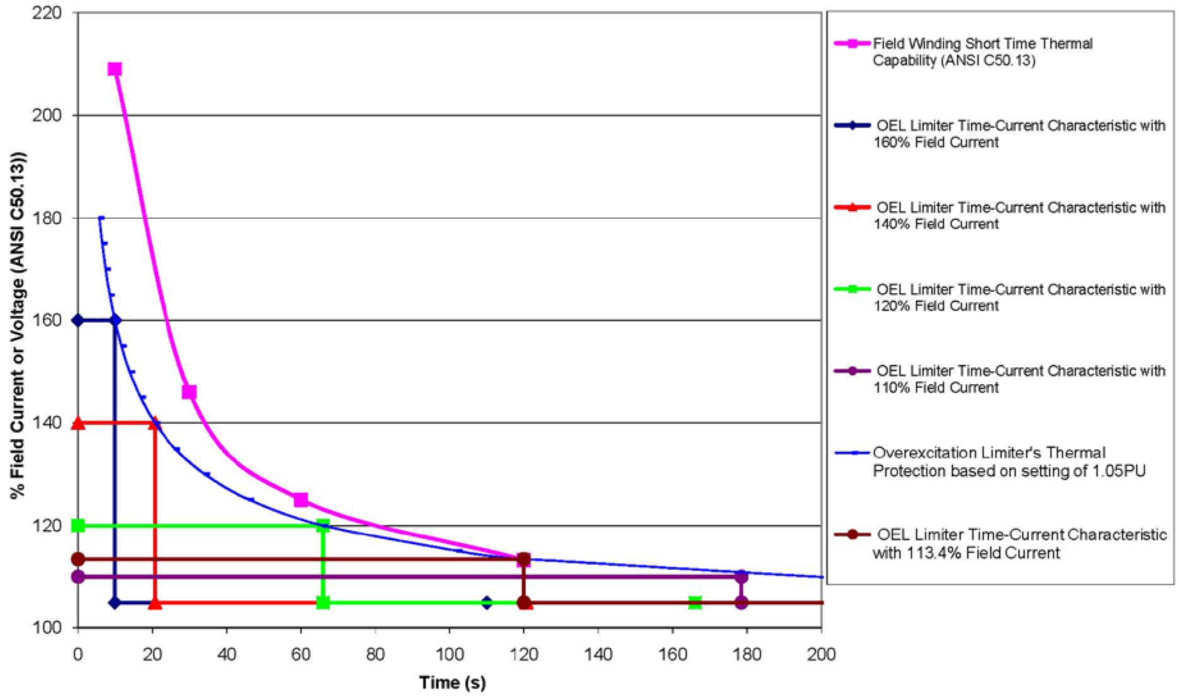
Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency




X (OHMS)
R (OHMS)
GENERATOR CAPABILITY
OVER EXCITATION TRIP
OVER EXCITATION LIMITER
RATED POWER FACTOR
STEADY STATE STABILITY LIMIT
LOSS OF FIELD ZONE 1
LOSS OF FIELD ZONE 2
UNDER EXCITATION LIMITER

Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot




220
200
180
160
140
120
100
% Field Current or Voltage (ANSI C50.13))
0
20
40
60
80
100
120
140
160
180
200
Time (s)
Field Winding Short Time Thermal Capability (ANSI C50.13)
OEL Limiter Time-Current Characteristic with 160% Field Current
OEL Limiter Time-Current Characteristic with 140% Field Current
OEL Limiter Time-Current Characteristic with 120% Field Current
OEL Limiter Time-Current Characteristic with 110% Field Current
Overexcitation Limiter's Thermal Protection based on setting of 1.05PU
OEL Limiter Time-Current Characteristic with 113.4% Field Current

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Approvals Required

PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner that owns synchronous condenser(s)

Applicable Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).
- Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

Conforming Changes to Other Standards
None

Effective Dates
PRC-019-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.
- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.
- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Justification for Phasing:

The coordination activities in this standard (PRC-019-1) are most effectively performed just prior to the performance of a reactive capability test, as required by MOD-025-2. Hence, the SDT has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2.

Retirements

None

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Approvals Required

PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner that owns synchronous condenser(s)

Applicable Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.
- Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System~~bulk power system~~.
- Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System~~bulk power system~~ at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).
- Any generator, regardless of size, that is a ~~B~~blackstart unit ~~Resource~~ material to and designated as part of a Transmission Operator's restoration plan.

Conforming Changes to Other Standards

None

Effective Dates

PRC-019-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- ~~By the first day of the first calendar quarter, one calendar year following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.~~
- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.
- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

In those jurisdictions where regulatory approval is not required:

- ~~By the first day of the first calendar quarter, one calendar year following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 20 percent of its applicable Facilities.~~
- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Justification for Phasing:

The coordination activities in this standard (PRC-019-1) are most effectively performed just prior to the performance of a reactive capability test, as required by MOD-025-2. Hence, the SDT has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2.

Retirements

None

Project 2007-09 - Generator Verification

Unofficial Comment Form
Generator Verification Standard Drafting Team
MOD-025-2

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to MOD-025-2. Comments must be submitted by 8 p.m. ET **October 29, 2012**. If you have questions please contact Stephen Crutchfield at Stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information:

The GV SDT posted the draft standard MOD-025-2 February 29 – April 16, 2012 for a formal comment period and initial ballot. Based on stakeholder feedback, the GV SDT made revisions to the standard to improve clarity.

Stakeholders provided many suggestions for improvements to the language of the standard. The majority of stakeholders agree with splitting the requirements as noted in the revised standard. The majority of the comments appear to be caused by confusion concerning what exactly is meant by separate testing as stated in Attachment 1. This seems to be caused by the fact that the Reactive Power verification requires Reactive Power data to be taken at several different Real Power operating levels. The intent of the standard drafting team is to allow verification of Real and Reactive Power at the same time if desired by the Generator Owner. This is not required. If the generator owner desires, they may do the two verifications at separate time. It is the opinion of the drafting team that since one of the operating points required for the Reactive Power verification is one with the Real Power output at the expected maximum, that it would be a simple and efficient method to use that operating point as the Real Power verification also.

The majority of commenters agree with the applicability to synchronous condensers greater than 20 MVA. Some commenters suggested that Synchronous Condensers do not have a full capability curve and therefore do not need to be tested at four points. While the GVSDT agrees that synchronous condensers do not have a typical capability curve, nor do they need one, a verification of the capability is needed similar to the verification of synchronous generators. We have added Note 5 to Attachment 1 to clarify this:

> "Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output."

A couple of stakeholders suggested having the applicability threshold increase from 20 MVA to 100 MVA. The GVSDT respectfully disagrees with regard to the 20 MVA threshold and believes that the same MVA threshold used for reactive capability of synchronous generators should apply to synchronous condensers.

Most stakeholders agree with having the verification data submitted to the Transmission Planner. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator, Balancing Authority or Planning Authority (Coordinator). As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the Operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (v5, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

    c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

The GVSDT has not revised the requirement with which continues to require the data be submitted to the Transmission Planner.

Several stakeholders disagree with the use of “bulk power system” in the applicability. The GVSDT has revised this to use the term “Bulk Electric System” instead. Concerns were raised regarding the verification schedule for entities that own five or fewer units. The GVSDT removed Sections 5.1.1 and 5.2.1. Entities that own one unit will be required to verify their unit within two years. Entities that own two units will be required to verify one unit within two years and both units within three years.

The GVSDT received several comments regarding the language in Attachment 1. As a result the GVSDT restructured item 2 of Attachment 1:

> 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by

unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

Some commenters had questions regarding Section 5.3 regarding wind farms. The GVSDT acknowledges that this statement was placed in the standard as an explanation and is not appropriate to be included as section 5.3. This information was expanded and included as a footnote rather than section 5.3:

> [1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Questions:

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The GVSDT has revised attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

2. **The GVSDT has revised the VSLs based on stakeholder comments. Do you agree with these revisions? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

3. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

   Comments:

Project 2007-09 Generator Verification

Unofficial Comment Form
MOD-027-1

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to MOD-027-1. Comments must be submitted by 8 p.m. ET on **October 29, 2012**. If you have questions please contact Stephen Crutchfield at Stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information:

The GVSDT posted the draft standard, MOD-027-1, February 29 – April 16, 2012 for a formal comment period and initial ballot. Based on stakeholder feedback, the GVSDT made revisions to the standard to improve clarity.

Most stakeholders agreed with the inclusion of partial load rejection testing and the inclusion of the applicable footnote. As many stakeholders noted, the appropriate footnote in the posted version of the standard was footnote 4, rather than 5 – and is currently footnote 2 in the current draft of the standard. Based on the comments received, the GVSDT made the following clarifications and revisions:

1. Numerous revisions made to clarify the language in Attachment 1, including adding row numbers. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1.
2. Revised sections 4.2.1, 4.2.2, and 4.2.3 to clarify the language.
3. Corrected numbering error of footnotes 4 and 5.
4. Corrected language in the footnote associated with partial load rejection, changing “on-load data” to “on-line data”
5. Reformatted Subpart 2.1.1 that breaks the three alternatives for acquiring the unit MW response for model verification into 3 bullets instead of listing all three in a sentence.

Stakeholders were evenly divided in their opinions regarding the periodicity aspects of Attachment 1. The GVSDT received suggestions for improvements and made the following clarifications and revisions:

1. Numerous revisions were made to clarify the language in Attachment 1.
2. Row numbers were added to Attachment 1.
3. The following text was removed from Requirement R2: “within 365 calendar days from the date that the response was recorded.”

4. In Attachment 1, the column title was revised from “Comments” to “Required Action”.
5. Removed 25/50/75/100% phase in from the Implementation Plan allowing GOs to install MW Recorders. This phase in unnecessarily complicated the Implementation Plan considering that the vast majority of units already have recorders or processes in place where MW response can be recorded and provided (from plant DCS systems, recorders, SCADA data, etc). Note that low resolution data, approximately 1 sample per second, is adequate for turbine/governor and load control or active power/frequency control function model verification.

There was a lot of industry confusion regarding the GVSDT attempt to effectively propose an exemption for base load units as the term “base load units” per say did not appear in the draft of the standard. We inadvertently used the term “base load” in the question on the comment form, which appears to have caused some confusion. The term “base load” is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.

Stakeholders provide additional suggestions for revisions to the standard. The following revisions were made by the GVSDT:

1. A significant number of industry commenters opposed the use of the term “bulk power system” in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as “bulk power system” is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.
2. For clarity and ease of reading, a paragraph within Requirement R3 was moved to the end of the requirement.
3. Change “facility” to “unit” in Measures 2 and 4 to match the terminology in the requirements. Also, other minor clarifications and edits made in the Measures.
4. Change “and” to “or” everywhere the phrase “and active power/frequency control functions” appears.
5. Revised Requirement R2 to remove “within 365 calendar days ......”
6. Revised Subpart 2.1.1 to specify “unit’s MW model response”.
7. Subpart 2.2 has been re-worded and merged into Subpart 2.1. The new verbiage makes it clear that the expert performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination

therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.

8. Revised Attachment 1 extensively for clarity, including removing specificity regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.
9. Revised the Effective Dates, and subsequently the Implementation Plan, to mirror the Effective Dates in the current draft of MOD-026 (verification of Excitation Control Systems).
10. Removed an extra word "that" (just before the word accurately) in the Purpose statement.
11. The qualifier "directly connected" was applied at the top level of the Facilities section (A4.2) to emphasize direct connection to the BES.
12. The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.
13. The SDT revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 8) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 5).

Periodicity Table (Attachment 1) for MOD-027-1:

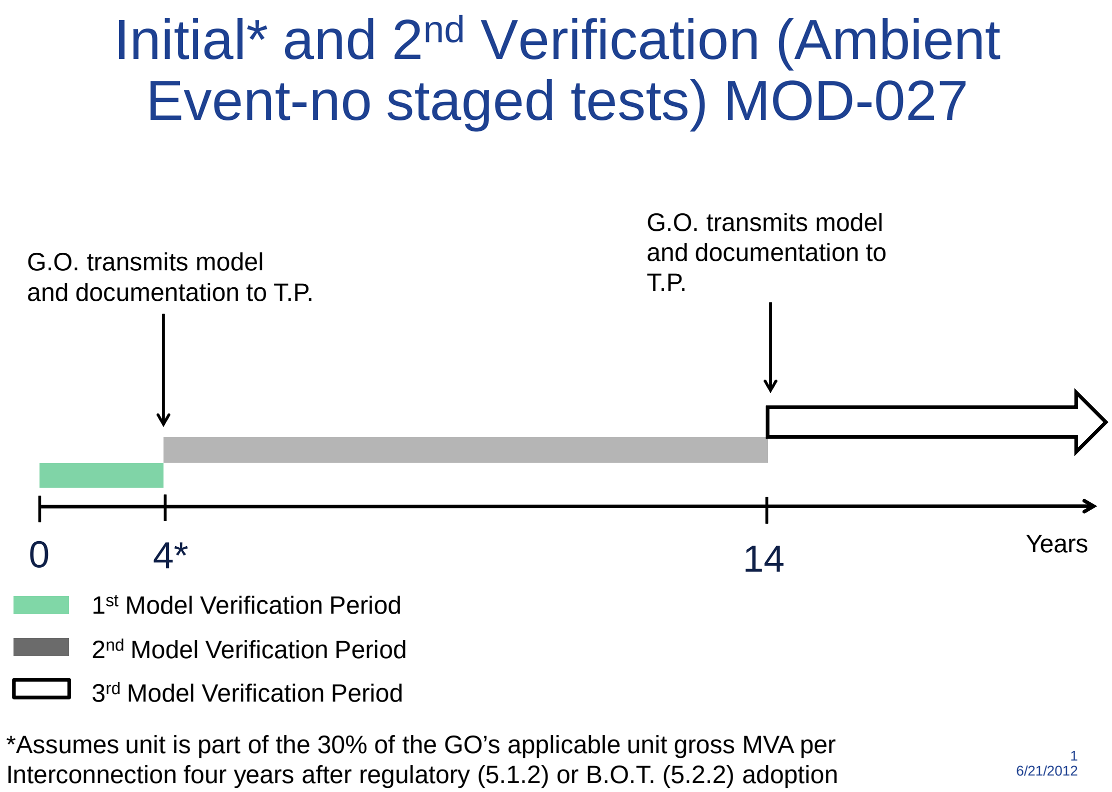
Based on industry comments from the last posting, the GVSDT modified the Periodicity Table (Attachment 1) to make it to make it significantly simpler and concise. In an effort to re-enforce the resulting modifications detailed in the current draft of the Periodicity Table, the following examples are offered by the GVSDT to aid industry in understanding the proposed model verification periodicity:

Periodicity Example 1:

The following timeline depicts a scenario where the Generator Owner has elected to utilize the ambient event methodology, as opposed to a staged test, to capture the unit's response to a frequency excursion and subsequently use that captured MW response to verify the model. In order to utilize the ambient event methodology, recorders need to be installed ready to capture the unit's MW response to an ambient event (system frequency excursion) by the first day of the first calendar quarter following either applicable regulatory approval or, in jurisdictions where no regulatory approval is required, following Board of Trustees adoption. As opposed to the last draft of the standard, the Periodicity Table (Attachment 1) no longer specifies when the Generator Owner has to capture the unit's Real Power response to a frequency excursion subject to the specification in Note 1 at the end of the Periodicity Table (including per unit hertz deviation and specifying that the unit has to be operating in a frequency responsive mode). The only requirement is that the verified model, documentation, and data must be transmitted to the Transmission Planner on or before the expected date.

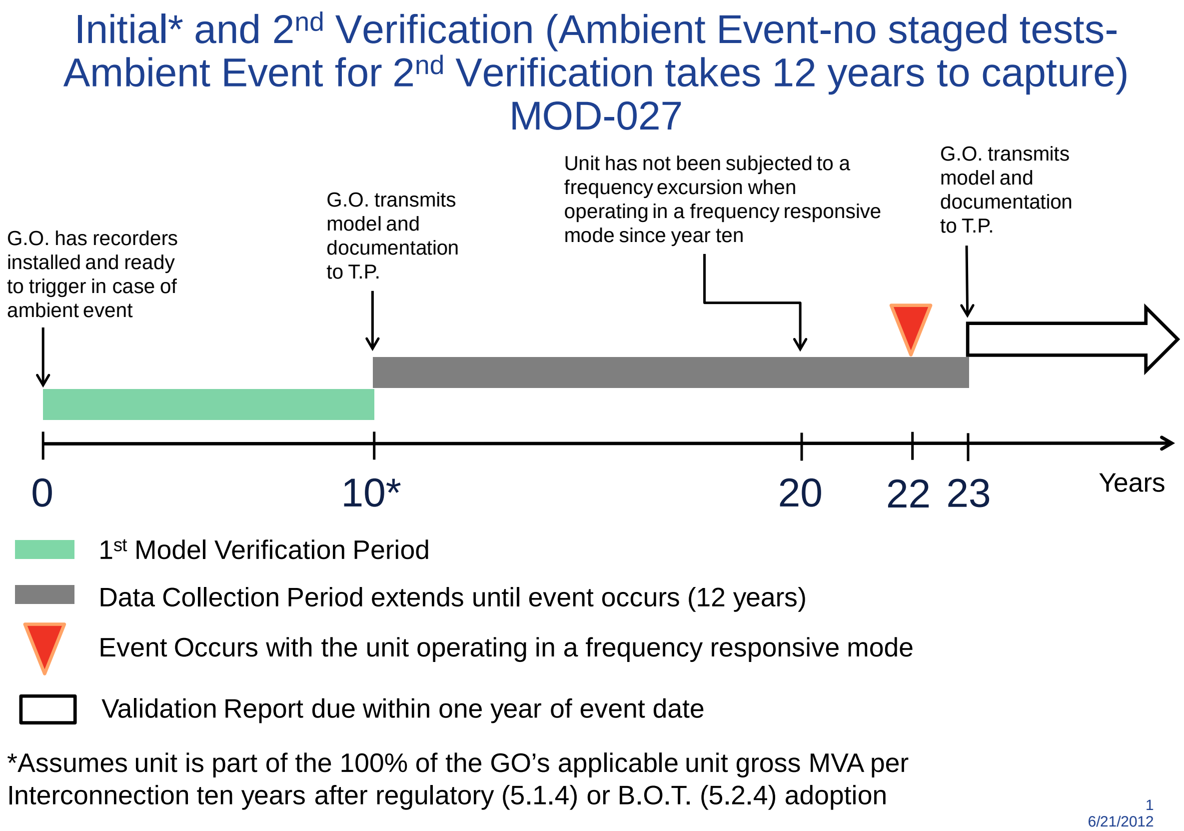
In the example below, it is assumed that a unit is part of the 30% of the Generator Owners applicable unit's gross MVA per Interconnection four years after regulatory or NERC B.O.T. adoption used to meet the Effective Date requirements for Requirement R2. The example assumes that the unit's Real Power response to a frequency excursion subject to the specification in Note 1 at the end of the Periodicity Table was captured and subsequently the model was verified and transmitted (along with verification documentation and data) to the Transmission Planner exactly on the effective date (Year 4).

Once the model is initially verified, the expectation is that it will be verified again after a 10-year period. For this scenario, the requirements detailing activities by exception do not occur (Requirements R3 – R4), which is expected to be the situation for the majority of the time. The example goes on to assume that the unit's Real Power response to a frequency excursion subject to the specification in Note 1 at the end of the Periodicity Table was captured between Year four and 14 and subsequently the model was verified and transmitted (along with verification documentation and data) to the Transmission Planner exactly 10 years after the submittal of the previous verification (i.e., 2nd verification and documentation submitted exactly at Year 14) – thus ending the 2nd model verification period and beginning the 3rd model verification period.



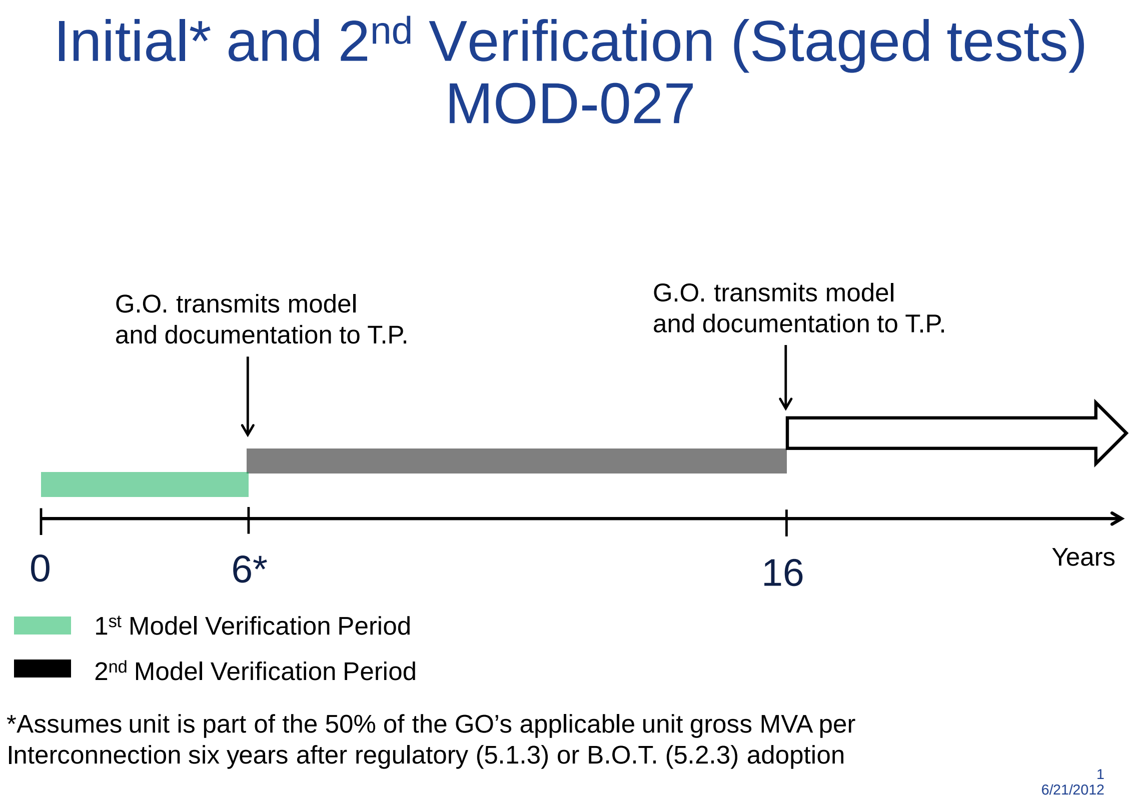
Periodicity Example 2:

The second example is much like Example 1 but with two differences. The first is that it is assumed that a unit is part of the 100% of the Generator Owners applicable unit's gross MVA per Interconnection required to be verified ten years after regulatory or NERC B.O.T. adoption. The second difference is that for the second verification, twelve years passed (Year 22) before the first time since the first verification the unit was operating in a frequency responsive mode and was subjected to a BES frequency excursion since the previous verification at Year 10. Thus, the verified model and documentation and data were not transmitted to the Transmission Planner until Year 23. This delay is acceptable, because Row 3 of the Periodicity Table states that if a unit if not subjected to a frequency excursion per Note 1 in time to meet the expected periodicity, then Requirement R2 of the standard is met with a written statement to the Transmission Planner. However, the verification model and documentation and data is due to the Transmission Planner 365 days after a frequency excursion per Attachment 1 Note 1:



Periodicity Example 3:

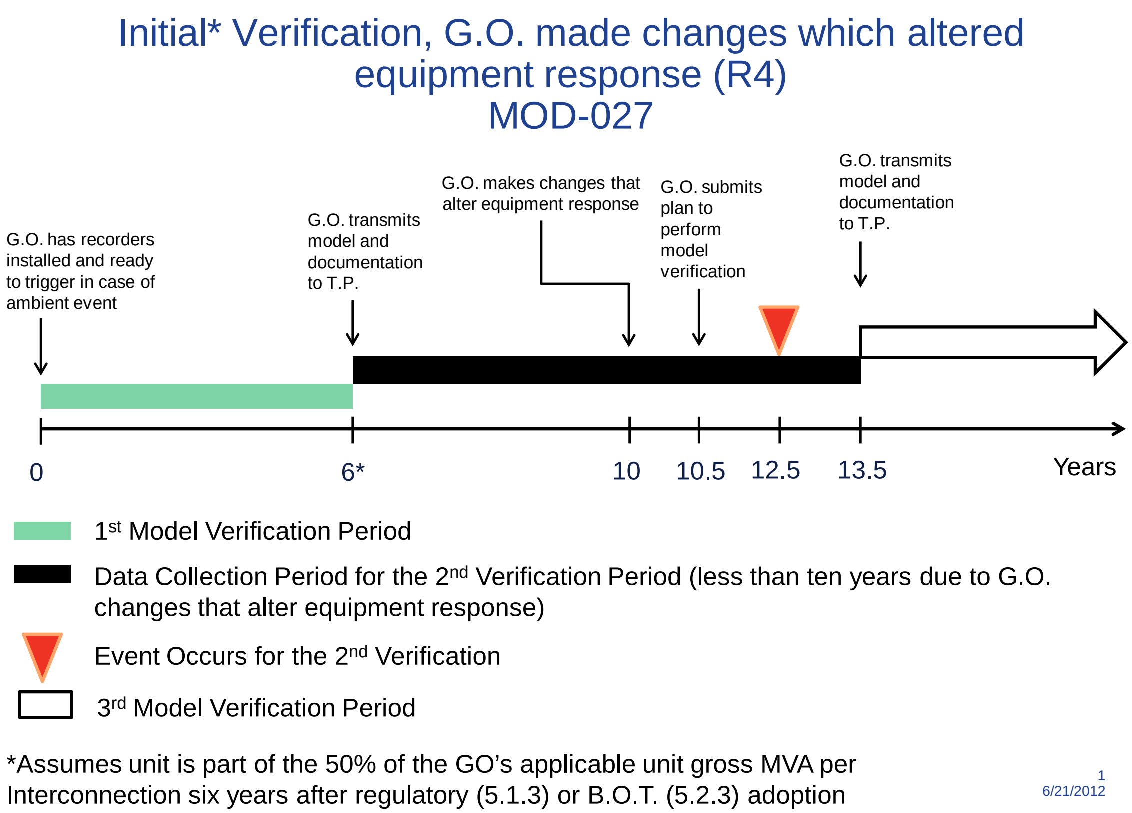
The third example assumes that the Generator Owner chooses to perform a staged test. It is assumed that a unit is part of the 50% of the Generator Owners applicable unit's gross MVA per Interconnection six years after regulatory or NERC B.O.T. adoption used to meet the Effective Date requirements for Requirement R2. The requirements detailing activities by exception do not occur (Requirements R3 – R4); which is expected to be the situation for the majority of the time. The first staged test has to be performed early enough for the subsequent model verification to be completed and transmitted to the Transmission Planner by Year six. For the second verification, another stage test is performed before the Year 10 anniversary date of the transmittal of the previous verification information – in for the subsequent model verification to be completed and transmitted to the Transmission Planner by Year 16.



Periodicity Example 4:

The fourth example details a scenario in which the GVSDT anticipates would rarely occur. The first six years is similar to Examples 1and 2 – it is assumed that a unit is part of the 50% of the Generator Owners applicable unit's gross MVA per Interconnection six years after regulatory or NERC B.O.T. adoption. The example assumes that the unit's Real Power response to a frequency excursion subject to the specification in Note 1 at the end of the Periodicity Table was captured and subsequently the model was verified and transmitted (along with verification documentation and data) to the Transmission Planner exactly on the effective date (Year 6).

However, the scenario assumes that four years after the transmittal of the model verification documentation and data for the first verification, the Generator Owner performs an activity which changes the equipment response (Year 10). As detailed in Requirement R4, the Generator Owner has 180 days to determine if updated model data can be provided, or if the model needs to be re-verified. The example timeline below assumes that later; i.e., the Generator Owner submits a plan in 180 days to re-verify the model. From that point, per the Periodicity Table, the Generator Owner begins to monitor for an appropriate ambient event while the unit is in a mode that it is expected to govern. Once the ambient event has occurred, then the Generator Owner has an additional year to transmit the model and documentation to the Transmission Planner. In this example, the ambient event with the unit in the proper operating mode occurred in two years after the Generator Owner decided to verify the model (i.e., Year 12.5), and the Generator Owner completed model verification and transmitted the results to the Transmission Planner at Year 13.5.



You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The GVSDT has revised Attachment 1 to attempt to clarify that, for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Do you agree with this revision? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

2. **The GVSDT has revised Attachment 1 to make the periodicity requirements more clear. Do you agree with these revisions? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

3. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

   Comments:

Project 2007-09 - Generator Verification

Unofficial Comment Form
PRC-019

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to PRC-019-1. Comments must be submitted by 8 p.m. ET **October 29, 2012**. If you have questions please contact Stephen Crutchfield at Stephen.crutchfield@nerc.net or by telephone at 609-651-9455.October

Background Information:

The GVSDT posted PRC-019-1 for a 45-day formal comment period with concurrent initial ballot from February 29 – April 16, 2012. Stakeholders provided feedback to make improvements to the standard and the GVSDT incorporated many of them in the standard.

A large majority of stakeholders agreed that the Applicability section as drafted was correct. A significant minority of stakeholders felt that the use of the term "Bulk Power System" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. A number of stakeholders objected to the inclusion of synchronous condensers and black start units. The SDT did not find that valid technical arguments were presented to remove these units from the Applicability and did not make the change.

A large majority of the stakeholders agreed with the revisions made to the examples in Section G. Exelon objected that the wording in the examples implied that the Steady State Stability Limit had to be calculated based on a fixed field current. The SDT modified the wording so that the SSSL can be calculated either with fixed or variable field current. Luminant objected to the inclusion of phase distance relay characteristics on the example graphs. The SDT agreed to remove these parameters from the graphs. Dominion asked the SDT to further clarify that the coordination does not apply to all generator protective functions. The SDT revised the wording to further clarify that concept. PPL asked for an all inclusive list of limiters and protective functions to be coordinated. The SDT declined this request.

A significant number of stakeholders felt that the use of the term "Bulk Power System" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. Several stakeholders objected to the 5-year interval for verifying coordination. The SDT felt the stakeholders did not present valid reasoning for extending the interval and did not change it. Several stakeholders argued that the risk associated with non-coordination did not warrant a "High" VRF. The SDT felt the arguments were valid and revised the VRF level for both Requirements R1 and R2 to "Medium". Several stakeholders felt the VSL language did not match the requirements, or questioned the tardiness intervals. The SDT agreed that the wording in the VSL's needed revision and made the suggested changes. The SDT did not change the tardiness increments in the VSL's since they come directly from NERC guidelines. Some stakeholders objected that the Effective Date section was too restrictive for entities with a small number of units. The SDT agreed and modified the first step of implementation to extend to two years instead of one and cover 40% of the applicable units.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The GVSDT revised the VRFs to "Medium" based on stakeholder feedback. Do you agree with the proposed revision? If not, please provide an alternative and supporting information in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

2. **The GVSDT revised the VSLs for each requirement based on stakeholder feedback. Do you agree with the proposed revisions? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

3. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

   Comments:

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval. The confusion centers on "approval" and when the 30-day period starts. 1311. We repeat our concern that Requirement R2, which specifies that the "regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval," is not clear. The requirement lacks a definition of what approval is required and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement. Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions	MOD-024-1; FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
can be determined. 1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary. 1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather		R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.		Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data
Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions can be determined. 1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The		The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner, including test conditions. Section 3 of Attachment is: 3. Record the following data for the verifications specified above: 3.1. The value of the gross Real and Reactive Power generating

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary. 1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate		capabilities at the end of the verification period. 3.2. The voltage schedule provided by the Transmission Operator, if applicable. 3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated. 3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as: • Ambient air temperature • Relative humidity • Cooling water temperature • Other data as applicable 3.5. The date and time of the verification period, including start and end time in hours and minutes. 3.6. The existing GSU and/or system Interconnection transformer(s) tap setting. 3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.		GSU transformer. 3.8. Whether the test data is a result of a staged test or if it is operational data.
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
Remove the fill-in-the-blank aspects (correct reference to "…Regional Reliability Organization's procedures…").	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Goal is uniform North American standards for real and reactive power verification. Look at regional requirements and identify the best practice, commonalities and differences, and whether differences are needed for reliability.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
No requirement for the RRO to demonstrate that its procedures result in accurate information of gross and net real power capability of generators for steady state models	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit	MOD-024-1; Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
Provide clarity where the Planning Authority is mentioned	MOD-024-1, Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.
Require verification of reactive power capability at multiple points over a unit's operating range. 1321. We disagree with commenters that verifying	MOD-025-1, FERC Order 693	Attachment 1 of MOD-025-2 addresses this directive. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW loading. However, other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.		Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data: 2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications. 2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval. The confusion centers on "approval" and when the 30-day period starts. 1322. We maintain the concern we expressed in the NOPR that Requirement R2 provides that the "regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval" and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.	MOD-025-1, FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1, R2 and R3 above.
Remove the fill-in-the-blank aspects (correct reference to "… Regional Reliability Organization's procedures…").	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Refer to MOD-024.	MOD-025-1, Fill-	The GVSDT has combined MOD-024 and MOD-025 into a single

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	in-the-blank Team	standard, MOD-025-2.
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
These standards do not provide for uniform testing of generator capability. The determination of which units are tested, how frequently they are tested, and the criteria used for determining capability are left to individual regions.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
R1.5.1: The benefit of verifying maximum capability of generators to absorb VArs at seasonal real power generation capability is unclear, particularly if this standard applies to virtually all generators. For the vast majority of units, the need to absorb VArs occurs during low-load conditions, when unit real power production is below maximum capability and the unit's ability to absorb VArs is greater. Therefore, the single datum for unit VAr absorption capability determined pursuant to this standard seems to be of little practical use, except for relatively few generators in a limited set of circumstances.	MOD-025-1, Phase III/IV Team	The Standard no longer references "seasonal capability." Attachment 1 of MOD-025-2 describes the required testing. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data: 2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications. 2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		during verifications. 2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure. 2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		must report the required data to its Transmission Planner. Please see Requirements R1, R2 and R3 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit.	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
Severity of non-compliance should be based on the percentage of the generator owner's total generation capability comprised of units required to be verified, rather than on the percentage (number) of generating units. Exempt units should be excluded from the total generation capability for determining level of non-compliance.	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
There is no clear reason for regional variations in capability testing. A generator in Georgia does not have more or less capability than an identical unit applied across the Florida line, despite the fact that one is in SERC and the other in FRCC.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard as well as regional variances have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Fundamental guidelines outlining some basic requirements (e.g., all units over 20 MW shall be tested annually under conditions that permit full net	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. All required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
output of the unit for normal operation) are lacking.		
Provide clarity where the Planning Authority is mentioned	MOD-025-1; Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.

A. Introduction

1. Title: **Verification of Generator Gross and Net Real Power Capability**

2. Number: MOD-024-1

3. Purpose: To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. Applicability

4.1. Regional Reliability Organization.

4.2. Generator Owner.

5. Effective Dates:

Requirement 1 and Requirement 2 **—** April 1, 2006.

Requirement 3 — January 1, 2007.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Criteria for reporting generating unit auxiliary loads.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.

R1.4. Periodicity and schedule of model and data verification and reporting.

R1.5. Information to be verified and reported:

R1.5.1. Seasonal gross and net Real Power generating capabilities.

R1.5.2. Real power requirements of auxiliary loads.

R1.5.3. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Real Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Real Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to those procedures, for verification and reporting of generator gross and net Real Power capability were provided to affected Generator Owners, Generator Operators,

Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Real Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous versions of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2, R1.4

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: There shall be a level two non-compliance if **both** of the following conditions are present:

2.2.1 Procedures did not meet two of the following requirements: R1.1, R1.2, R1.4

2.2.2 No evidence that procedures were distributed as required in R2.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet either R1.5.1, R1.5.2 or R1.5.3

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a generator owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a generator owner's units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a generator owner's units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% of a generator owner's units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3. 8. Removed the word "less" after 94% in section 3.4. Level 4.	01/20/06

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Reactive Power Capability**
2. **Number:** MOD-025-1
3. **Purpose:** To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.
4. **Applicability**
   4.1. Regional Reliability Organization.
   4.2. Generator Owner.
5. **Effective Dates:**

   Requirement 1 and Requirement 2 — January 1, 2007

   Requirement 3:

   January 1, 2008 — 1st 20% compliant

   January 1, 2009 — 2nd 20% compliant

   January 1, 2010 — 3rd 20% compliant

   January 1, 2011 — 4th 20% compliant

   January 1, 2012 — 5th 20% compliant

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Criteria for reporting generating unit auxiliary loads.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.

R1.4. Periodicity and schedule of model and data verification and reporting.

R1.5. Information to be reported:

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.

R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.

R1.5.3. Verified Reactive Power of auxiliary loads.

R1.5.4. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the

Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Reactive Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to these procedures, for verification and reporting of generator gross and net Reactive Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Reactive Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous version of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2 or R1.4.

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: Procedures did not meet two or three of the following requirements: R1.1, R1.2 or R1.4.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet R1.5.1, R1.5.2, R1.5.3, or R1.5.4.

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a Generator Owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a Generator Owner's units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a Generator Owner's units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% less of a Generator Owner's units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3.	01/20/06

Project 2007-09 Generator Verification
MOD-024-1 DRAFT Mapping Document

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-024-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Real Power Capability.	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability.
3. Purpose: To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.
R1. The Regional Reliability	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined. Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, Applicability**,** which follows the Registry Criteria.	**4.2 Facilities:** 4.2.1 For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**Requirement R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	**Requirement R1** references **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be performed.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 **NERC Board Approved**	**Comment**	**Proposed Standard MOD-025-2**
		the date the data is selected for verification using historical operational data.
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirement R1 references Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Real Power generating capabilities. **R1.5.2.** Real Power requirements of auxiliary loads.	**Requirement R1** references **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.5.3. Method of verification, including date and conditions.		containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Real Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

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Project 2007-09 Generator Verification
MOD-024-1 DRAFT Mapping Document

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Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-024-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Real Power Capability.	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability.
3. Purpose: To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.~~To require applicable entities verify generator Real and Reactive Power capability and Synchronous Condenser Reactive~~

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		~~Power Capability and to supply capability date to planning entities data for assessing Bulk Electric System (BES) reliability.~~
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner ~~with~~ that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System~~bulk power system~~. 4.2.3 Generating plant/Facility greater than 75

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System~~bulk power system~~.
R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	Regional applicability is eliminated and functional entity responsibility is defined. Verification, including reporting, is addressed throughout proposed Standard.	**Requirements R1, R2 and R3** defines the verification and data reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, Applicability**,** which follows the Registry Criteria.	**4.2 Facilities:** 4.2.1 For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System~~bulk power system~~. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		connected to the Bulk Electric System~~bulk power system~~. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System~~bulk power system.~~
R1.2. Criteria for reporting generating unit auxiliary loads.	**Requirement R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such	**Requirement R1** references **Attachment 1.** Section 2 of **Attachment 1**	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor:

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	prescribes the details of how the verification should be performed.	Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirement R1 references Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
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R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Real Power generating capabilities. **R1.5.2.** Real Power requirements of auxiliary loads. **R1.5.3.** Method of verification, including date and conditions.	**Requirement R1** references **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		for a staged test or the date the data is selected for verification using historical operational data.
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Real Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

Project 2007-09 Generator Verification
MOD-025-1 DRAFT Mapping Document

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2. Title: Verification of Generator Gross and Net Reactive Power Capability	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.
R1. The Regional Reliability Organization	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
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shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, **Applicability,** which follows the Registry Criteria.	**4.2 Facilities:** For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard. **Attachment 1,** section 4.1 allows engineering estimates in those situations where metering to measure a reactive load is not installed.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data,	**Requirements R2 and R3,** reference **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
commissioning data, performance tracking, and testing, etc.	performed.	synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data
R1.4. Periodicity and schedule of model	**Requirements R2 and R3,**	**R2.** Each Generator Owner shall provide its Transmission

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
and data verification and reporting.	reference **Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Reactive Power generating capabilities while at the Seasonal Real Power generating capability as reported in accordance with MOD-024-2. **R1.5.2.** Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc. **R1.5.3** Verified Reactive Power of Auxiliary loads.	**Requirements R2 and R3,** reference **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor:

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.5.4. Method of verification, including date and conditions.		Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data
R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2** and **R3**.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Reactive Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2 and R3**. The Transmission Owner has been added to include	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
	synchronous condensers that are under the control of the TO.	Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data

Project 2007-09 Generator Verification MOD-025-1 DRAFT Mapping Document

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-025-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Reactive Power Capability	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure net accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.~~To require applicable entities verify generator Real and Reactive Power capability and Synchronous Condenser Reactive~~

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		~~Power Capability and to supply capability date to planning entities data for assessing Bulk Electric System (BES) reliability.~~
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner ~~with~~ that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System~~bulk power system~~. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating)

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		directly connected to the Bulk Electric System~~bulk power system~~.
R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:	Regional applicability is eliminated and functional entity responsibility is defined Verification, including reporting, is addressed throughout proposed Standard.	**Requirements R1, R2 and R3** defines the verification and data reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, **Applicability,** which follows the Registry Criteria.	**4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System~~bulk power system~~. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System~~bulk~~

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		~~power system~~. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System~~bulk power system~~.
R1.2. Criteria for reporting generating unit auxiliary loads.	**R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard. **Attachment 1,** section 4.1 allows engineering estimates in those situations where metering to measure a reactive load is not installed.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.**
R1.3. Acceptable methods for model	**Requirements R2 and R3,**	**R2. Each Generator Owner shall provide its Transmission**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	reference **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be performed.	**Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reaactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirements R2 and R3,** reference **Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive~~l~~**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data**
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Reactive Power generating capabilities while at the Seasonal Real Power generating capability as reported in accordance with MOD-024-2. **R1.5.2.** Verified Reactive Power	**Requirements R2 and R3,** reference **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
limitations, such as generator terminal voltage limitations, shorted rotor turns, etc. **R1.5.3** Verified Reactive Power of Auxiliary loads. **R1.5.4.** Method of verification, including date and conditions.		**calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data**
R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2** and **R3**.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.		**units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		verification using historical operational data
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Reactive Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2 and R3**. The Transmission Owner has been added to include synchronous condensers that are under the control of the TO.	**R2. Each Generator Owner shall provide its Transmission Planner with verification of the ~~Real~~ Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **2.1. Verify the Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.** **2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.** **R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive~~l~~ Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]** **3.1. Verify the Reactive Power capability of its synchronous**

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		condenser units in accordance with Attachment 1. **3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data**

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control; or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup Facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and Facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical Facilities
- Appropriate use of transmission Loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4; whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for MOD-025-2:

There are three requirements in MOD-025-2. Each requirement was assigned a "Medium" VRF.

VRF for MOD-025-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each Requirement in MOD-025-1 is assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirements R2 and R3. Each requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC's definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The "Medium" VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R2:

- FERC Guideline 2 — Consistency within is similar in scope to Requirements R1 and R3. Each Requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept, and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit as specified in this standard.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The "Medium" VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each requirement in MOD-025-1 is assigned a "Medium" VRF. Requirement R3 is similar in scope to Requirements R1 and R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0, Requirements R1 and R2, in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC's definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned “Medium” VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R3 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-025-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for MOD-025-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms, and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action, and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation, and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-027-1:

There are five requirements in MOD-027-1. Three requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-027-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This

requirement is administrative in nature for providing instructions and data used for performing model verification. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 which have an approved VRF of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contains Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R6 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-027-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-027-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is timely. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is complete. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-019-1:

There are two requirements in PRC-019-1 and both have been assigned a "Medium" VRF.

VRF for PRC-019-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R1 is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to periodically verify voltage regulation controls, limiters and protection coordinated with unit

and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 and Part 1.1 have a reliability objective to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-019-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R2 is similar in concept with both PRC-010-0 Requirement R1 and PRC-014-0 Requirement R1, both of which require 5-year verification of protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify coordination following setting changes affecting unit or synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 has a high reliability objective to specify the periodicity for verifying voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination following a change to equipment settings. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal,

or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. . The “Medium” VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-019-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for PRC-019-1 Requirement R1:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	The proposed VSLs are based on increments of tardiness for completing the required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider performing required action per the procedure specified by listed parts. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-019-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSLs are based on increments of tardiness for competing required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider performing required action per the procedure specified by listed parts. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-019-1:
There are two requirements in PRC-019-1 and both have been assigned a "Medium~~High~~" VRF.

VRF for PRC-019-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. ~~contains Parts that are procedural in nature for satisfying the main requirement. The VRF is only applied at the Requirement level.~~ The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R1 is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. ~~In addition, and as is generally the case with PRC standard VRF definitions, t~~This requirement is assigned a "~~High~~Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. ~~Failure to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.~~ Failure to periodically verify ~~or following setting changes affecting coordination verify~~ voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition~~could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition~~. Therefore the assigned "~~High~~Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 and Part 1.1 have a reliability ~~high risk~~ objective to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The "~~High~~Medium" VRF assigned is based on the ~~high risk~~reliability objective specified.

VRF for PRC-019-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. ~~contains Parts that are procedural in nature for satisfying the main requirement. The VRF is only applied at the Requirement level.~~ The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R2 is similar in concept with both PRC-010-0 Requirement R1 and PRC-014-0 Requirement R1, both of which require 5-year verification of protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed

as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. ~~In addition, and as is generally the case with PRC standard VRF definitions, t~~This requirement is assigned a "~~High~~Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. ~~Failure to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.~~ Failure to ~~periodically~~ verify coordination ~~or~~ following setting changes affecting unit or synchronous condenser coordination ~~verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination~~ in the Long-term Planning Time Horizon is a requirement ~~in the planning time frame~~ that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition~~could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.~~ Therefore the assigned "~~High~~Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 has a high reliability~~isk~~ objective to specify the periodicity for verifying voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination following a change to equipment settings. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. . The "~~High~~Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-019-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-019-1 Requirement R1:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.~~The NERC VSL guidelines are satisfied by incorporating binary VSL~~	This is a new Requirement and does not have a prior level of compliance.	The proposed VSLs are based on ~~is binary. Binary requirements are categorized as severe~~increments of tardiness for completing the required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSL~~'~~s do not expand on what is required in the requirement. The VSL~~'~~s assigned only consider performing required action per the procedure specified by listed parts. Proposed VSL~~'~~s are consistent with the requirement.	Proposed VSL~~'~~s are based on a single violation and not a cumulative violation methodology.

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	~~elements as the requirement has a reliability objective that is either met or not.~~				

VSLs for PRC-019-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL~~'~~s are based on increments of tardiness for competing required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSL~~'~~s do not expand on what is required in the requirement. The VSL~~'~~s assigned only consider performing required action per the procedure specified by listed parts. Proposed VSL~~'~~s are consistent with the requirement.	Proposed VSL~~'~~s are based on a single violation and not a cumulative violation methodology.

Standards Announcement

Project 2007-09 Generator Verification

Formal Comment Period Now Open: September 28, 2012 – October 29, 2012

Upcoming:
Successive Ballots and Non-binding Polls: October 19 – October 29, 2012

Now Available

A formal comment period for:

- Draft 3 of **MOD-025-2** – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability,
- **MOD-027-1** – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions,
- **PRC-019-1** – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection,
- Draft 4 of **MOD-026-1** – Verification of Models and Data for Generator Excitation Control Systems Functions and Plant Volt/Var Control Functions, and
- **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions

is open through **8 p.m. Eastern on Monday, October 29, 2012.** Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, October 19, 2012** through **8 p.m. Eastern on Monday, October 29, 2012.**

Instructions for Commenting

A formal comment period for all five Generator Verification standards is open through **8 p.m. Eastern on Monday, October 29, 2012.**

Please use the links below to the electronic comment forms to submit comments:

MOD-025-2
MOD-027-1
PRC-019-1
MOD-026-1
PRC-024-1

If you experience any difficulties in using the electronic forms, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form links shown above. During the ballot window, balloters who wish to submit comments with their ballot *may no longer enter comments on the balloting screen*, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

- MOD-025-2 ballot bp-2007-09_MOD-025-2_in@nerc.com
- MOD-027-1 ballot bp-2007-09_MOD-027-1_in@nerc.com
- PRC-019-1 ballot bp-2007-09_PRC-019-1_in@nerc.com
- MOD-026-1 ballot bp-2007-09_MOD-026-1_in@nerc.com
- PRC-024-1 ballot bp-2007-09_PRC-024-1_in@nerc.com

Next Steps

Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will be conducted beginning on Friday October 19, 2012 through 8 p.m. Eastern on Monday, October 29, 2012.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and

recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

These standards were revised and posted for subsequent comment periods. The drafting team incorporated industry feedback to improve the standards and has posted them for a concurrent comment and ballot period.

Additional information is available on the project page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement
Project 2007-09 Generator Verification

Formal Comment Period Now Open: September 28, 2012 – October 29, 2012

Upcoming:
Successive Ballots and Non-binding Polls: October 19 – October 29, 2012

Now Available

A formal comment period for:

- Draft 3 of **MOD-025-2** – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability,
- **MOD-027-1** – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions,
- **PRC-019-1** – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection,
- Draft 4 of **MOD-026-1** – Verification of Models and Data for Generator Excitation Control Systems Functions and Plant Volt/Var Control Functions, and
- **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions

is open through **8 p.m. Eastern on Monday, October 29, 2012.** Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, October 19, 2012** through **8 p.m. Eastern on Monday, October 29, 2012.**

Instructions for Commenting
A formal comment period for all five Generator Verification standards is open through **8 p.m. Eastern on Monday, October 29, 2012.**

Please use the links below to the electronic comment forms to submit comments:

MOD-025-2
MOD-027-1
PRC-019-1
MOD-026-1
PRC-024-1

If you experience any difficulties in using the electronic forms, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form links shown above. During the ballot window, balloters who wish to submit comments with their ballot *may no longer enter comments on the balloting screen*, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

- MOD-025-2 ballot bp-2007-09_MOD-025-2_in@nerc.com
- MOD-027-1 ballot bp-2007-09_MOD-027-1_in@nerc.com
- PRC-019-1 ballot bp-2007-09_PRC-019-1_in@nerc.com
- MOD-026-1 ballot bp-2007-09_MOD-026-1_in@nerc.com
- PRC-024-1 ballot bp-2007-09_PRC-024-1_in@nerc.com

Next Steps

Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will be conducted beginning on Friday October 19, 2012 through 8 p.m. Eastern on Monday, October 29, 2012.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and

recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

These standards were revised and posted for subsequent comment periods. The drafting team incorporated industry feedback to improve the standards and has posted them for a concurrent comment and ballot period.

Additional information is available on the project page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 – Generator Verification

Successive Ballot Results

Now Available

Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRF/VSLs concluded on Monday, October 29, 2012 (some of the ballots and non-binding polls were extended until a quorum was reached).

Voting statistics for each of the ballots are listed below, and the Ballots Results page provides a link to the detailed results.

Standard	Approval	Non-binding Poll Results
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions and Plant Volt/Var Control Functions	Quorum: 75.55% Approval: 76.50%	Quorum: 75.88% Supportive Opinions: 79.95%
PRC-024-1 – Generator Performance During Frequency and Voltage Excursions	Quorum: 75.00% Approval: 57.24%	Quorum: 75.40% Supportive Opinions: 55.90%
MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	Quorum: 83.61% Approval: 68.31%	Quorum: 77.94% Supportive Opinions: 70.72%
MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	Quorum: 82.34% Approval: 71.53%	Quorum: 78.06% Supportive Opinions: 74.18%
PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	Quorum: 82.07% Approval: 70.64%	Quorum: 78.51% Supportive Opinions: 69.39%

Next Steps
The standard drafting team (SDT) will consider all comments submitted, and based on the comments will determine whether to make additional changes. If the SDT determines that no substantive changes are required to address the comments on a particular standard, a recirculation ballot of that standard will be conducted. If the SDT determines that substantive changes are required on a standard, the revised standard will be submitted for quality review and subsequently posted for a successive ballot.

Background
The purpose of Project 2007-09 Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The Project 2007-09 Generator Verification SDT based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The SDT has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The SDT has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid-2006 through mid-2007:

- PRC-019-1 — Coordination of Generating Unit or Plant Capabilities , Voltage Regulating Controls, and Protection PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Additional details are available on the project page.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2007-09 Successive Ballot MOD-025-2
Ballot Period:	10/19/2012 - 10/31/2012
Ballot Type:	Successive
Total # Votes:	306
Total Ballot Pool:	366
Quorum:	**83.61 % The Quorum has been reached**
Weighted Segment Vote:	68.31 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	41	0.621	25	0.379	13	11
2 - Segment 2.	9	0.6	5	0.5	1	0.1	1	2
3 - Segment 3.	82	1	30	0.526	27	0.474	12	13
4 - Segment 4.	27	1	11	0.688	5	0.313	4	7
5 - Segment 5.	91	1	31	0.508	30	0.492	12	18
6 - Segment 6.	50	1	23	0.639	13	0.361	7	7
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	5	0.5	0	0	1	1
9 - Segment 9.	3	0.3	3	0.3	0	0	0	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	0	1
Totals	**366**	**7**	**154**	**4.782**	**102**	**2.219**	**50**	**60**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	

1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		

3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	

4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	

5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	

6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

404.446.2560 voice : 404.446.2595 fax
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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Ballot Results	
Ballot Name:	Project 2007-09 Successive Ballot MOD-027-1
Ballot Period:	10/19/2012 - 10/31/2012
Ballot Type:	Successive
Total # Votes:	303
Total Ballot Pool:	368
Quorum:	**82.34 % The Quorum has been reached**
Weighted Segment Vote:	71.53 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	92	1	49	0.721	19	0.279	11	13
2 - Segment 2.	9	0.6	4	0.4	2	0.2	1	2
3 - Segment 3.	82	1	41	0.672	20	0.328	8	13
4 - Segment 4.	27	1	13	0.765	4	0.235	3	7
5 - Segment 5.	91	1	34	0.557	27	0.443	9	21
6 - Segment 6.	50	1	27	0.692	12	0.308	4	7
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	5	0.5	0	0	1	1
9 - Segment 9.	3	0.3	3	0.3	0	0	0	0
10 - Segment 10.	7	0.6	4	0.4	2	0.2	0	1
Totals	**368**	**7**	**180**	**5.007**	**86**	**1.993**	**37**	**65**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		

3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish	John D Martinsen	Affirmative	

	County			
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	

5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
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6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
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6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
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6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

Legal and Privacy

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2007-09 Successive Ballot PRC-019-1
Ballot Period:	10/19/2012 - 10/31/2012
Ballot Type:	Successive
Total # Votes:	302
Total Ballot Pool:	368
Quorum:	**82.07 % The Quorum has been reached**
Weighted Segment Vote:	70.64 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	94	1	43	0.623	26	0.377	11	14
2 - Segment 2.	9	0.6	6	0.6	0	0	1	2
3 - Segment 3.	83	1	36	0.581	26	0.419	7	14
4 - Segment 4.	25	1	12	0.667	6	0.333	2	5
5 - Segment 5.	90	1	32	0.552	26	0.448	10	22
6 - Segment 6.	50	1	23	0.622	14	0.378	6	7
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	5	0.5	0	0	1	1
9 - Segment 9.	3	0.3	3	0.3	0	0	0	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	0	1
Totals	**368**	**7**	**165**	**4.945**	**99**	**2.055**	**38**	**66**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	

1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Negative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		

3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Negative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	

5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Negative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

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Non-binding Poll Results

Project 2007-09 MOD-025-2

Non-binding Results	
Non-binding Poll Name:	Project 2007-09 Non-binding Poll MOD-025-2
Poll Period:	10/19/2012 - 10/31/2012
Total # Opinions:	272
Total Ballot Pool:	349
Summary Results:	77.94% of those who registered to participate provided an opinion or an abstention; 64.24% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	

1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck		
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	

1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson		
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		

3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	

3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	LaGen	Richard Comeaux		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	

5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	

NERC

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah		

6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	James D Burley		

10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	

Non-binding Poll Results

Project 2007-09 PRC-019-1

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-09 Non-binding Poll MOD-027-1
Poll Period:	10/19/2012 - 10/31/2012
Total # Opinions:	274
Total Ballot Pool:	351
Summary Results:	78.06% of those who registered to participate provided an opinion or an abstention; 68.93% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	

1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck		
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	

1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson		
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	

3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	

3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	LaGen	Richard Comeaux		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky	Mike D Kukla	Negative	

	peak power plant project			
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	

5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	

6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	

Non-binding Poll Results

Project 2007-09 PRC-019-1

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-09 Non-binding Poll PRC-019-1
Poll Period:	10/19/2012 - 10/31/2012
Total # Opinions:	274
Total Ballot Pool:	349
Summary Results:	78.51% of those who registered to participate provided an opinion or an abstention; 63.63% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	

1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Theresa Allard		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	

1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson		
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Negative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	

3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	

3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Negative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Abstain	

5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	

5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	

6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Negative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts	Donald Nelson	Affirmative	

	Department of Public Utilities			
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	

Individual or group. (48 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)
Comments (48 Responses)
Question 1 (34 Responses)
Question 1 Comments (42 Responses)
Question 2 (29 Responses)
Question 2 Comments (42 Responses)
Question 3 (0 Responses)
Question 3 Comments (42 Responses)

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Group
Domion
Mike Garton
Yes
Dominion suggests that footnote 1 not contain the capitalized term Wind Farm Verification as this is not defined in either this standard or the NERC Glossary of Terms.
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability…." It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years. The phrasing regarding applicability should be made more consistent. The criterion, "Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System," in para. 4.2.3 appears to state that a station with two 500 MW fossil units (meeting NERC registry criteria) and a standby, 10 MW diesel genset connecting to the 13.2 kV bus (not meeting the NERC registry criteria), for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory position, however, by saying that "For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." This would be better stated as, that "For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." Applying on p.16 an "unduly restricted" classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in our comments above are not related to transmission system conditions. Our concerns are amplified by the statement, "Observe auxiliary bus voltage limits," in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT's intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus drop-out? Doing so would constitute an unacceptable operational practice. Note 2 should be deleted as well ("While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification….") since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, "The recorded Mvar values were

adjusted to rated generator voltage, where applicable," on P.21 should also be deleted. Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720 MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently incorrect, given the dictionary definitions of "normal" as meaning standard, usual, typical etc and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range. The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing…," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR test. The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per our comments above. The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," is incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to. Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended.
Without some exemption, we disagree with the GVSDT linking generator applicability of this standard to the Compliance Registry Criteria. Instead, the approach to applicability should be the same as what is used/proposed in MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual units greater than 100 MVA directly connected to the BES, etc.) Other than that size unit, use regional criteria to address any smaller units identified as critical to the BES in a given region. Consistency of criteria among the standards within this Project 2007-09 should be the same.
Individual
Brian Bejcek
Wolverine Power Supply Cooperative, Inc.
Yes
Yes
This standard is redundant. We are already required by MISO to provide real power data. It would be more logical for this standard to be applicable to the RTO because they are already asking for most of this data. I would rather have MISO expand what they are asking for and have them pass the data along to NERC, than to have to comply with two entities asking for the same thing with slightly different methods.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
1. In Attachment 1 Section 2.2.1, we take issue with the requirement to verify reactive power capability at the minimum real power output. We are not convinced this is necessary for BES reliability. The reactive capability at this point can be estimated by the GO with sufficient accuracy for the planning model. Verification of reactive output at minimum real power requires considerable effort and resource scheduling flexibility for data which can be readily estimated without adverse impact to the BES. Especially for large units, it may require a multiple day effort to verify reactive power at the minimum and maximum real power points, due to issues with auxiliary equipment. 2. Attachment 2 On the One Line Diagram and the following data table, it is indicated that the net unit capability is to be provided at the GSU high-side (Point F). This should be revised to allow the GO to provide the net capability at the GSU low-voltage side instead. There may not be adequate metering capability at the GSU high-side, wheras metering at the generator voltage

level is commonly available.
Individual
Jim Watson
Dynegy
No
Recommend deleting the requirement in Attachment 1 section 2.2.1 to verify reactive power at minimum load. This puts the unit in an unstable condition and then stresses it by varying reactive power leading to the increased likelihood of a unit trip.
Yes
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Paragraph 4.2 contains several typos and the intent is not clear. Recommend revising 4.2 to read: “An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.”
Yes
In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027.
Group
Southern Company
Shammara Hasty
No
Yes
The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. An engineering study for reactive capability is an option that needs to be allowed by this standard Currently, the standard is more of a performance test than a model verification test – the requirements do not directly fulfill the purpose. Applying an “unduly restricted” classification to reactive power verification results that fall short of 50% of the thermal capability curve (page 16) creates a technical error that does not prove or disprove the reactive capability of the generating unit. The D-curve represents the thermal characteristic of a single component (generator). The reactive capability of a generation unit system is also a function of other factors. These other factors include the transmission system bus voltage, GSU impedance and tap setting, unit auxiliary transformer and downstream station service transformer impedances and tap settings, station service bus loadings and voltage limits, and the excitation limiter settings. Staged testing has limitations when attempting to prove a unit’s reactive capability. We currently use an engineering assessment approach that establishes a unit’s expected reactive capabilities using an analytical model. The model has been validated using historical operational data. The model takes into account all the above factors and is used to estimate the unit’s reactive capabilities for extreme system

voltage conditions when unit’s reactive limits will be challenged. The limits are then reviewed by plant operations to ensure any operational limitations have been identified and factored into the assessment. This has proven to be a better process for establishing the reactive limits needed for the transmission planning system models than the use of staged test data. MOD-025 should not require “staged testing” without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the testing. The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability. The recorded Mvar values were adjusted to rated generator voltage, where applicable,” on p.21 should be deleted because it does not make sense to do this.
Individual
Lynn Schmidt
NIPSCO
This is the information that generator owners are supposed to provide every year to transmission owners as part of the MOD-10 data submittal. Why a new standard is being developed instead of modification of the existing MOD-10 is questionable. The burden for complying with this standard falls almost entirely with the generation group, e.g., electric production. Given the above, Transmission Planning recommends a vote in favor of this standard.
Group
Northeast Power Coordinating Council
Guy Zito
If the primary purpose of obtaining net Real Power and net Reactive Power is to build system models to support planning studies, then the Drafting Team should consider that MOD-025 may not be required and could be eliminated. Under Standard IRO-010-1a the Reliability Coordinator can require GOs and TOs to submit Real and Reactive Power data in a format the RC deems necessary. The detailed requirements of MOD-025 can be addressed in IRO-010-1a. Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. If the Drafting Team believes that a separate Standard to verify the gross and net Real and Reactive Power of the turbine generator is required, then MOD-025 should be limited to requiring the reporting of maximum Real and Reactive Power only. In our view the detailed data requirements specified in Attachment 1 and 2 are not required for planning studies. The data in Attachments 1 and 2 have value to plant personal to evaluate unit efficiency and performance, but this data is not needed to support reliability. This data is more relevant to market functions.
Group
Tennessee Valley Authority
Brandy Spraker

No
1. Att 1, Periodicity for conducting a new verification: 1. For staged verification; recommend changing the allotted time to make a change to 12 months. From Att 1: "... of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months" - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. 2. Att 1, Periodicity for conducting a new verification: 2. For verification using operational data; recommend changing the allotted time to make a change to 12 months. Att 1: "... discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months" - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. 3. Att 1, Periodicity for conducting a new verification:, 1 For Staged verification; and 2. For verification using operational data; both steps require verification at least every five years. Recommend verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, "6 calendar years." Justification is to coordinate protective system relay testing during plant outages with the real and reactive power testing that can be performed during outage shut-down or start-up. 4. Attachment 1, 3.6, add "voltage ration and," as follows: The existing GSU and/or system interconnection transformer(s) voltage ration and tap setting. Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies "transformer(s) tap setting"; Attachment 2, had data entries for "Voltage Ratio." Both values are legitimate transformer parameters. 5. Recommend Att 1, 4., be titled as "Record the following auxiliary load information:" Justification is that the current "step 4" is more of a substep to this new "step 4" description. 6. Recommend Att 1, 4., current step text be moved to a substep 4.1, "Develop a simplified key one-line diagram ... " Justification is that this step is similar to the current "steps 4.1 and 4.2" 7. Recommend renumbering steps "4.1 to 4.2" and "4.2 to 4.3." Justification is to change the current "step 4 to 4.1." See items 4 and 5, above. 8. Recommend changing the current "step 4.2 / recommended step 4.3" to read as follows: "If an adjustment is requested by the TP, then develop the relationship between test conditions and generator output so that the amount of Real Power that can be expected to be delivered can be determined from a generator at different conditions, such as peak summer conditions [remove can be determined]... " Justification is to reword for clarity.
1. Entire Attachment 2, recommend linking Att 2 data entries to Att 1 requirements by adding (e.g. Att 1 requirement ______) in parenthesis, to each Att 2 line/bullet. Justification is to define the source requirement for the data. 2. Attachment 2, Summary of Verification, recommend adding the following bullet under "Transformer Voltage Ratio: ..." Add: "Transformer Tap Setting: GSU ____, Unit Aux ____, Station Aux ____, Other Aux ____" Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies "transformer(s) tap setting"; Attachment 2, had data entries for "Voltage Ratio." Both values are legitimate transformer parameters. 3. Overall Standard, The focus of this standard appears to be on testing rather than on verifying the limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test. Justification is that the requirements do not directly fulfill the purpose. 4. Overall Standard, recommend removing the requirements to perform "staged testing." Justification is that staged testing should only be required if requested by the TOP. Justification is that verification of the true reactive limits via staged testing often produces less than optimal results because of transmission system constraints. 5. Standard, 4.0 Applicability, The unit size applicability for MOD-025-2 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027 (i.e. MOD-026-1 Draft, 4.2, Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ...(including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ...(including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ...(including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.)
Group
Pepco Holdings Inc and Affiliates
David Thorne
Agree
Individual
Cristina Papuc
TransAlta Centralia Generation LLC
Yes

Yes
N/A
Individual
Nazra Gladu
Manitoba Hydro
No
General Comments - There is reference to certain actions that would be ‘desirable’ although not strictly required by the standard. This type of language can be problematic if the entity is held to this, or asked to explain why they did not meet the ‘desirable’ level. There appear to be requirements embedded in the attachment, and there should be no requirements here. For example, the word “shall” should be removed (since it implies a requirement) from (i) page 15 (clean version) “If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled . . . . .” and (ii) page 16 “ . . . then the next verification shall be by another staged test, not operational data:” Another example which sounds like a requirement is on page 17 “Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.” Additionally, in 4.2 (i) “TP” should be expanded to Transmission Planner and (ii) the first sentence is worded poorly and should be clarified. Section 2.1 - Manitoba Hydro recommends removing the words “over excited” and replacing the words “normal (not emergency)" with "nominal". Section 3.7 - “(real or reactive)” should be changed to “(real and reactive)”. Page 15 (clean version) - The word “Load” should not be capitalized. Page 17 (clean version), Note 1 - Manitoba Hydro suggests replacing ‘improper tap settings’ in Note 1 which reads “…such as rotor thermal instability, improper tap settings,…” with “improper voltage ratios”. Page 18 (clean version), Note 5 - Manitoba Hydro suggests removing Note 5 which reads “Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.” Such descriptive wording is not required in a standard and should be left for reference books.
Yes
None.
1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? 2. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled “Consideration for early Compliance” with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1).
Group
pacificorp
ryan millard
No
PacifiCorp does not support the minimum one hour hold requirement for verifying a generating unit’s maximum real power and lagging reactive power in Section 2.1.1 of Attachment 1. The one hour hold is excessive and fails to correlate to how a machine responds to a system event that only lasts for a few minutes. The one hour requirement also puts unnecessary stress on plant equipment and directly contradicts the WECC Synchronous Machine Reactive Limits Verification Guideline that recommends holding a unit for a minimum of 15 minutes. PacifiCorp has followed this guideline since it was approved in 1996, and recommends this same standard to be applied in Attachment 1.
Yes
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes

Individual
Winnie Holden
PSEG
Yes
Yes
We voted “Negative” on this standard the reasons shown below: This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1. 1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a “team” with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as “applicable facilities,” while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments: “The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.” The SDT responded as follows: “The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.” In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.” PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.” We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. This SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1. 2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1 R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all “modelers,” the result will be outdated data in someone’s model, which can have a bad result. The team should have one broad “data sharing” policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Xcel Energy questions the reliability value of determining the maximum leading reactive power value at maximum real power output. This is not an operating regime for most generating units, so operational data will not be available, and operating at maximum power would normally occur during higher system load conditions when the loss of a generating unit due to a mistake during a test would stress the system more severely.
Individual
Michelle R. D'Antuono

Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)
Yes
In our view, Ingleside Cogeneration LP believes the technical language used in the latest version of MOD-025-2 Attachment 1 has been refined to an acceptable point.
Yes
Ingleside Cogeneration LP agrees that the ability for Transmission Planners and other operating entities to be able to rely on a generator's available real and reactive capacity under system duress is essential to BES reliability. In addition, the technical veracity and implementation time frames in the latest version of MOD-025-2 are far improved over previous versions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R1 and R2) must contain language that focuses on the strength of the validation process – not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed – even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
ATC recommends the following changes: Attachment 1, Periodicity for new verification Item 3 – Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or a mutually agreed verification date." Attachment 1, Verification Specifications Item 2.1.2 – The wording is unclear near the end of Item 2.1.2. ATC recommends this be changed to read, "Reschedule the test of the facility within six months after being unable to test at or above the 90 percent threshold".
Individual
Ken Gardner
Alberta Electric System Operator (AESO)
1. In section 4.2 The AESO considers the existing applicability for reactive power verification to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect.
Individual
Thad Ness
American Electric Power
Yes

Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by: a. In the Implementation Plan, under the Section "In those jurisdictions where regulatory approval is required:", adding a phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner…" b. In Section A5.1 of the standard, adding the same phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval," and before "each Generator Owner…". 2. There are four measurements of "Gross Reactive Power Capability" for generators: over-excited and under-excited at minimum and maximum active power outputs. Which one of the four measurements should be recorded in Appendix 2 under "Gross Reactive Power Capability"?
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Individual
Wryan Feil
Northeast Utilities
Yes
Yes
No comment
Individual
Brian Evans-Mongeon
Utility Services
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Seattle City Light
paul haase

No
Attachment 1, Section 2.1 explicitly states to run each unit at maximum real power and lagging reactive power for a minimum of one hour. Due to constraints of the load, water flow, or other operational characteristics such as generators' thermal limits this is typically not possible.
No
The VSL associated with Attachment 1 Section 2.1 will often be violated, because due to constraints of load, water flow, or other operational characteristics such as generators' thermal limits it is typically not possible to to run each unit at maximum real power and lagging reactive power for a minimum of one hour as required.
Individual
Daniel Duff
Liberty Electric Power LLC
Agree
NAGF
Group
Florida Municipal Power Agency
Frank Gavvney
A synchronous condenser can be owned by either a TO or GO. For instance, there are installation of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO whoever owns the synchronous condenser.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Although supportive of the standard drafting team’s efforts, LES believes MOD-025 could be further enhanced in consideration of the following recommendations. - Recommend Attachment 1 “Periodicity for conducting a new verification” be revised to require verification of the Real Power capability on an annual basis with Reactive Power remaining at every 5 years. In consideration that regions such as the MRO and SPP maintain existing procedures requiring members to perform Real Power verification at a minimum of annually, LES believes this reduced timeframe is not only reasonable but also achievable for entities. Additionally, it seems reasonable to expect a re-verification be performed if the Real Power is reduced by as little as 5 percent as several units with that level of lost capacity could be significant in adversely affecting the integrity of the BES. - Recommend Attachment 1 “Verification specifications for applicable Facilities” Part 3.4 be modified to specify the duration of the verification period and that the data supplied should be an average of the verification test period. - Per the standard, the purpose of MOD-025 is to ensure accurate information is available for the planning models in order to assess BES reliability. NERC annually builds 4 seasonal peak models (summer, winter, spring and fall) in addition to a spring minimum model. Within these models the TPs must provide Real Power maximum and minimum values and up to 10 sets of correlated real and reactive values in order to model a generators “D curve”. As such, LES would recommend that the GO develop these values and provide them to the TO. While Real Power Max is tested it is only done under the conditions of a single season, it would then be up to the TP to adjust the MW output for the other 3 seasons. LES believes the GO is the more appropriate person to make these adjustments rather than the TP. Additionally, Real Power minimum testing is not addressed within this standard. LES believes with the increase in highly variable generation, such as wind, generators may end up operating at their minimums much more than they have done historically and therefore Real Power minimums should be verified on an annual or 5 year basis as well. In terms of Reactive Power generation, a GO should be required to go beyond what is required in the current Attachment 2 and align with the number of correlated Real/Reactive sets which the TP is required to provide in their models to NERC. - In further support of BES reliability, LES recommends that the net Real Power output for generating facilities be adjusted based on a high temperature for the month based on the model that the Real Power output is being developed for, i.e. summer, winter, spring, fall, or minimum model. The criteria for determining what should be used for a high temperature adjustment point could be an average of the entity’s high temperature for the month over a ten-year period or possibly the 0.4% ASHRAE temperature could be used. LES believes it would not be unreasonable to expect that data be supplied by the

GO for the seasons required for model submission by the TP.
Group
MEAG Power
E Scott Miller
Agree
Southern Company Services, Inc. - Gen
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum (NAGF)group for MOD-025.
Group
JEA
Thomas McElhinney
JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power System Planning as a Transmission Owner that owns synchronous condensers agrees with the revisions made to Attachment 1.
Yes
Idaho Power System Planning agrees with the revised VSLs.
Idaho Power System Planning as a Transmission Owner that owns synchronous condensers has the following comments for the GVSDT to consider: Attachment 1 - Item 2.1.1 lists the verification duration for a synchronous generating unit at maximum real power and maximum reactive power with a one hour testing duration. Idaho Power System Planning comments that the voltage schedule may be difficult to maintain during a one hour test at maximum reactive power for a one hour test during for N-0 system conditions. Idaho Power System Planning asks the GVSDT to consider a 30 minute testing duration for performing the verification to be consistent with the 30 minute duration established for operators to make manual system adjustments following contingency events. Attachment 1 - Item 2.1.2: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for variable generating units. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for variable generating units for the maximum reactive capability test. Attachment 1: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for synchronous condensers. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for synchronous generators for the maximum reactive capability test. Requirements to submit verification with 90 days of test date are unreasonable. 365 days is more reasonable, and is consistent with MOD-026-1 and MOD-027-1.
Individual
John Yale
Chelan PUD
Yes
Yes
1. It is unclear how auxiliary load should be calculated where several units share a common station service power supply and all units are not in operation (multi unit hydro plant). Suggest some guidelines in allocation

in these cases should be included. 2. It may not be possible to generate maximum real power for one hour for hydro with small reservoir volumes. Similar to run of river hydro, reservoir volume or other license requirements may restrict this ability. Suggest a similar allowance in these cases to the run of river power qualificaiton. 3. R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which engineering analysis is required for model verification. 4. It may not be possible to test full reactive capability at minimum power for hydro units due to the broad capability curve without exceeding TOP established voltage schedules. I suggest going to some percentage of the "full" value to verify the curve with concurrance of the TOP and TP in these cases or test documentation of limiter settings. If the GO is requried to perform staged test, the TOP and RC must be able to support it. Some system should be established where this can not be done.
Individual
Robert Casey
Georgia Transmission Corporation
Yes
Yes
Individual
Maggy Powell
Exelon Corporation and its affiliates
No
Attachment 1 (general comment): Exelon appreciates the addition by the GVSDT of the exclusion that nuclear units are not required to perform Reactive Power verification at minimum Real Power output (Attachment 1 Section 2.2.3); however, as stated in the previous comments, Exelon still is concerned that nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with nuclear plant specific NRC operating license. In response to Exelon's comments in the 9-27-12 Consideration of Comments, the GVSDT states that they "disagree with not requiring a verification to define the unit's reactive capability" and further states that they are "aware of nuclear units that have been safely tested to their leading power factor limits." Although the GVSDT may purport that it is safe to perform such testing there is not one unique design for a nuclear generating unit in the NERC Regional Entities. Exelon continues to believe that there should be a provision in the Standard to allow for such an exemption based on considerations for nuclear unit regulatory, unit stability or other potential equipment restrictions. To address the concern that the GVSDT has related to providing a blanket exemption for nuclear units, Exelon suggests that such an exemption must be justified, documented in writing, and accepted by the Transmission Planner. Exelon suggests that a new note be added to Attachment 1 as follows: "If a unit is restricted due to other regulatory, unit stability, plant operating procedures, or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate. A generating unit with such a restriction must be justified, documented in writing and accepted by the Transmission Planner." Periodicity for conducting a new verification: Attachment 1 Section related to the periodicity for conducting a new verification (page 15 of 22) second paragraph states: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." Experience shows that maintaining the plant’s substation bus voltage within the scheduled voltage range at some arbitrary value is often inadequate to allow maximum VAR output during staged Reactive Capability testing. In such cases the system operator would need to adjust the substation voltage, potentially close to a schedule limit. Exelon suggests that the sentence be revised as follows: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to coordinate with the Generator Operator to adjust the plants substation bus voltage as required to accommodate the desired reactive output."

No
Although Exelon agrees with a majority of the revisions, it does not seem reasonable to assign a Severe VSL for a potential administrative oversight for not submitting the data to the Transmission Planner within a set period of calendar days equally to a complete failure to perform the required testing for an applicable generating unit. Exelon suggests that the administrative requirement for submitting data within a set period be limited to maximum of a High VSL and the application of the specific submission time periods be adjusted for the Low and Medium VSLs and the Severe VSL be revised to reflect inability to produce sufficient data to substantiate that the required testing was performed (i.e., the Generator Owner may have performed the test but is unable to produce any data to support the testing). As an example, the proposed example revision to the Severe VSL is as follows: The Generator Owner failed to produce data upon request of the Transmission Planner. OR The Generator Owner failed to verify the [applicable test] per Attachment 1 of an applicable generating unit.
Section D, "Compliance," Part 1.2, "Evidence Retention," (page 6 of 22) first paragraph is unnecessary and redundant since the retention periods specified are for the time period since the last compliance audit. Exelon suggests that this paragraph be deleted in its entirety.
Individual
Kirit Shah
Ameren
No
While it is a step in the right direction to direct the Transmission Operator to take measures to maintain the system bus voltage of the plant under test at an acceptable level during the reactive power capability testing of the plant, this still does not mean that the plant would necessarily be able to reach its full reactive power output capability during the test. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then we believe that there needs to be some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed.
No
There seems to some discrepancy in the reporting date that the VSLs are based on when using the operational data to verify. The first section in the VSL for R1 is worded slightly differently than the same portion of the VSL for R2 and R3. For R1, the reporting date seems to be based on the date that the data is selected for verification based on historical data, whereas for R2 and R3 the reporting date seems to be based on the date when the historical operating point was reached. Please clarify the SDT’s intention to have such a difference, as it could make a big difference in meeting the reporting date deadline, and cause confusion among Generator Owners.
(1)We believe that for sets of generators that are designed and operated identically, there should be a provision allowing use of “Sister Units” for compliance as done in MOD-026. (2)We believe the 5 year cycle with a 66 month limit is too stringent. We request that due to possible outage scheduling issues or other impacts, extending this 66 month limit by 18 months allowing a maximum of 84 months between test verifications. (3)Was it the intent of the SDT to leave out a minimum verification time of one hour for both MW and MVAR verification? Could the SDT please clarify their intention and if a minimum of one hour was intended?
Group
Luminant
Brenda Hampton
Yes
No
Luminant disagrees with the expanded VSLs and recommends that the SDT return to the VSL list in the previous posting. Luminant believes that the original VSL list is comprehensive and does not require expanding to include completeness of the data reported, or specific compliance to items, 1, 2, and 3 of the “Periodicity for conducting a new verification.”
Individual
Don Jones
Texas Reliability Entity
No

1) Attachment 1, 2.2.2: We recommend changing the reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. 2) Attachment 1, 2. We disagree with the statement that "…previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). Unless there is a documented system limitation, an accurate test should result in 90% or better of the D-curve, after correction for ambient conditions. 3) Attachment 1, 2.2 does not require wind and photovoltaic "applicable facilities" to verify Reactive Power capability at a minimum Real Power output. The ISO may still have reactive requirement for renewable resources at minimum output levels. If so, the resource should be required to demonstrate and test against those requirements? 4) Attachment 1, 2.1.1: What is the basis for "one hour?" Attachment 1, 3.1 says to record the value at the end of the verification period. What is the expected value(s) to be provided for the hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and wind turbines may not allow for a full hour. Current ERCOT regional criteria for the Reactive Power leading and lagging test duration is 15-minutes. 5) Attachment 1, 3.2: If there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. 6) As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. 7) Attachment 1, section 3: Generator Owner should also include the D-curve with the verification data. For many air-cooled units, the real and reactive capability can vary significantly with ambient temperature. The Transmission Planner needs both the ambient temperature and the D-curve data to verify the validity of the test. 8) Attachment 1, 3.4: we suggest re-wording to "… perform corrections to Real Power ***and Reactive Power*** for different ambient conditions…"
1) Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning and Operations models for specific periods. 2) In section 4, the phrase "directly connected to the Bulk Electric System" may have the unintended consequences of excluding a generator unit connected to the BES through a 69/138 kV autotransformer (for example). Suggest removing 'directly' from these requirements. 3) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. 4) TRE recommends changing to "Planning Authority or Transmission Planner" in the requirement sections instead of "Transmission Planner". The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. 5) The Functional Entities are listed as the Generator Owner and the Transmission Operator. However, the VAR standards have the Transmission Operator provide the Generator Operator a voltage or reactive schedule and require the Generator Operator to maintain that voltage or reactive schedule. Should the Generator Operator be included in this standard for verification and data reporting? There are many cases where the Generator Owner is not the Generator Operator and confusion could result (or incorrect data/testing) if different criteria were provided. 6) Overall the timing is too long. Waiting 12 calendar months for verification impacts reliability. Based on this requirement, the capability could be reduced by 50% but not tested for 12 calendar months (or longer). That could put significant strain on a local system that may not be tested for an extended period and yet be compliant with the standard.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
(1) We believe that Attachment 1 is clearer but we still have a few issues that the drafting team should address. In response to our previous comments, the drafting team indicated that a staged test is required prior to the use of operational data. In other words, the first verification must be through a staged test. The response to comments cited a sentence in sub-section 2 of the "Verification specifications for applicable Facilities:" in Attachment one as the reason. Essentially, it says if the previous test was unduly restricted, then the next verification should be a staged test. We do not think this is straight forward. What if there was no test? Could a test that did not occur be called unduly restricted? It would be much clearer for the drafting team to state directly either in Attachment 1, the requirements, the implementation plan or the effective date section that the first test must be a staged test. (2) In subsection 3.4 of the "Verification specifications for applicable Facilities:" section of Attachment 1, we disagree with including "Other data as applicable." It is ambiguous, open ended and will only lead to inconsistent enforcement. Who decides what is applicable? The TP? The GO? The auditor? What happens if an auditor decides they believe a piece of data should be included but the TP and GO agree it shouldn't? If the other needed data cannot be enumerated, an open ended statement such as the one discussed here should not be added as a "catch all." This type of statement is

unduly burdensome.
Yes
(1) What measure does the effective date use when determining percentage of applicable Facilities that must be completed by the given date? Is it a percentage based on the net nameplate rating of the generator? We suggest this should be stated directly to avoid conflicts between what the auditor assumes versus what the registered entity assumes. (2) Attachment 2 discusses subtracting tertiary real and reactive power to get net real and reactive power, yet there is no entry for it. Should there be an entry added in the form? (3) The response to our last comments regarding inclusion of the last verification column indicated that a note would be added to indicate that this column would be blank for the initial verification. We could not find the note. Please add it. We were concerned a similar issue to the one experienced with the Protection System Maintenance and Testing standard would be experienced. In the PRC standard, auditors interpreted statements in the standard to require data prior to the enforceable date even though registered entities were not required to keep it. It resulted in a number of violations. (4) In applicability sections 4.2.1 through 4.2.3, please change “directly connected to the BES” to “that are part of the BES”. Per the BES definition, generation units can be and are part of the BES. Using “directly connected to the BES” could draw in a non-BES unit. (5) How will mothballed units be handled? If a mothballed unit is returned to service, is it treated like a new unit with the return date serving as the commissioning date?
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No comments on this question.
No
No comments on this question.
A stated purpose of Generator Verification is “to ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.” Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets’ capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load’s process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load’s production schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same. Additionally, the SDT should define the term ‘Synchronous condenser’ so that it is clear that a large synchronous motor is not a synchronous condenser.
Group
Duke Energy
Greg Rowland
No
Delete Note 3 on page 18 of the clean version, and delete the reference to Note 3 located on page 15 under “Verification specifications for applicable Facilities: #2”. If a unit is equipped with AVR, the test must be conducted with the AVR in service.
Yes
1) Attachment 2, Summary of Verification – Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) In the Consideration of Comments Report the Standard Drafting Team agreed to make this change, but it was overlooked. 2) The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test – the requirements do not directly fulfill the purpose. 3) Leading VAR Staged Testing – Leading VAR staged testing provides little benefit to the BES and should only be performed once in an initial staged test or validation. The fact that the regions will not be able to provide operational data for the leading VAR test points requested, proves that the system usually doesn’t

require leading VARS. In the situations such as system recovery and lightly loaded BES where leading VARS may be required, the initial testing and validation that the unit’s heat removal capability (such as lagging VAR operational data) is sufficient, should serve as satisfactory verification of the unit’s capability. The risk (and cost) of repeated operation of the unit in the maximum leading VAR is not warranted for the little benefit it provides to the BES. The risk of Step Iron degradation and loss of synchronous operation every five years far outweighs the benefit such testing would provide the BES once the unit has been proven capable. The lagging VAR capability test or validation will prove that the unit’s heat removal capability has not been compromised. MOD-025-2 should be reworded to only require periodic validation (either by staged testing or operational data) for lagging VARS, and that periodic leading VAR testing only be required if the unit is not capable of passing the lagging VAR capability test or validation. 4) Applicable Facilities – Verification of units between 20 MVA and 100 MVA provide little benefit to the BES for the risk and cost of performing the staged test for these units. The maximum VAR contribution for these units is in the 5 to 20 MVAR range, and the risk and cost for testing, documentation and auditing of units of this size is not warranted for the small benefit gained. If there is a specific need for a particular small unit to provide VAR support due to regional constraints, then it should be validated. But to require validation for all the small units that have little impact on the reliability of the BES, the cost is not warranted. The unit size applicability for PRC-019-1 and MOD-025-2 should be set equivalent to that specified by MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery, NERC Reliability Compliance Coordinator
No
Attachment 1, Parts 2.2.1 and 2.2.2, AECI does appreciate adequate Attachment 1 allowances for voltage-schedule restrictive operating conditions, so that actual Maximum and Minimum reactive capabilities that simply cannot be attained, are not required, as acknowledged per Notes 1 & 2. However we do question the value to industry, beyond initial testing per this standard, of the 5-year retesting and believe this Requirement will eventually be removed unless redrafted per responsible entities' internal controls program expectations. We do however agree with the requirement to retest when unit conditions change sufficiently to warrant retesting.
Yes
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Group
SERC Planning Standards Subcommittee
Charles Long
Yes
Paragraph 4.2 contains several typos and the intent is not clear. Recommend revise 4.2 to read: “An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.”
Yes
In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Russell Noble
Cowlitz PUD

No
Cowlitz supports the comments developed by the NAGF SRT: 1. The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability…." It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years. 2. The semantics regarding applicability should be made more consistent. The criterion, "Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System," in para. 4.2.3 appears to state that a station with two 500 MW NERC-registered fossil units and a standby, non-NERC-registered10 MW diesel genset connecting to the 13.2 kV bus, for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory position, however, by saying that "For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." This would be better stated as, that "For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." 3. Applying on p.16 an "unduly restricted" classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error that is fatal to the approvability of MOD-025-2 in its present form. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. 4. Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in comment #3 above are not related to transmission system conditions. Our concerns are amplified by the statement, "Observe auxiliary bus voltage limits," in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT's intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus dropout? Doing so would constitute an inacceptable operational practice. 5. Note 2 should be deleted as well ("While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification….") since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, "The recorded Mvar values were adjusted to rated generator voltage, where applicable," on P.21 should also be deleted. 6. Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720 MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently an oxymoron, given the dictionary definitions of "normal" as meaning standard, usual, typical, etc. and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range. 7. The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing…," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR test. 8. It would be helpful to state any coordination of units within a plant that is required or preferred for VAR testing. Running for example a three-unit plant with all units exporting MVARs together, then all importing together, will produce more conservative reactive power capabilities (i.e. the aux bus limits will sooner be encountered) than is the case for testing units one at a time with the other two under normal operation. Pull-together/push-together is the more realistic approach, however, for simulating the response of the plant to a Disturbance of the BES. 9. The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per comment #6 above. 10. The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," are incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to. 11. Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended. 12. GSU losses should have a separate line in Att. 2, since they are not specifically a

tertiary load (item C in the Att. 2 diagram). 13. MOD-025 should not require "staged testing" without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the testing. 14. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability.
Individual
Don Schmit
Nebraska Public Power District
Agree
MRO NSRF

Individual or group. (46 Responses)
Name (31 Responses)
Organization (31 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (46 Responses)
Question 1 (31 Responses)
Question 1 Comments (41 Responses)
Question 2 (31 Responses)
Question 2 Comments (41 Responses)
Question 3 (0 Responses)
Question 3 Comments (41 Responses)

Individual
Jim Watson
Dynegy
Yes
Yes
Some smaller Generator Owners have little experience in this type of testing. If possible, it is suggested more detail be placed in Attachment 1 regarding what constitutes an acceptable test, i.e., template.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
We would suggest that there be something added to give those GO’s who have not modified their plants to be able to opt out of the re-verification. There is a concern that the updated data would be at least a year out of step with the development of the ERAG model in the eastern interconnect.
Group
Northeast Power Coordinating Council
Guy Zito
Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Tennessee Valley Authority
Brandy Spraker
Yes
No
Attachment 1, Row Number 5, Recommend deleting “at the same physical location” from the Verification condition. The first condition is recommended to read “Existing applicable unit that is equivalent to another unit(s),”

Justification is that if a GO has units that are equivalent and meet the "sister" criteria, the standard does not need to be restricted to the same physical location. The GO identical equipment at different physical locations are still equivalent.
Step 4.2.3, Recommend adding "in" to the requirement to read "Generation in the ERCOT Interconnection ..." Justification is to be consistent with similar steps 4.2.1 and 4.2.2.
Individual
Cristina Papuc
TransAlta Centralia Generation LLC
Yes
Yes
N/A
Individual
Lynn schmidt
NIPSCO
Verification requirements would be burdensome, e.g., model response by a load rejection test or comparison with a system frequency excursion may be of only limited value. Another basic problem with this standard is the unnecessary back and forth between generation owners and transmission planners in the data development and collection. This standard could be greatly simplified for all involved parties with reporting requirements similar to MOD-025 where the generation owner provides information to the transmission planner upon the installation of new equipment or the modification of existing equipment. Given the above, Transmission Planning recommends a vote against this standard in its present form.
Individual
Nazra Gladu
Manitoba Hydro
Yes
None.
Yes
None.
R1 - The text would be more clear if rewritten to read 'Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner:' 4.2 - The language immediately preceding the bullets is unclear: 'that meet the following' should perhaps be rewritten as 'provided they meet the following'. Effective Date Section 5.1 - Manitoba Hydro recommends changing the "R6" to "R5" because there is no "R6" in the standard. General Comment - Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?
Group
pacificorp
ryan millard
Yes
Yes
Group
Bonneville Power Administration
Chris Higgins
Yes

Yes
Individual
Winnie Holden
PSEG
Yes
Yes
We voted “Negative” on this standard the reasons shown below: This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1. 1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a “team” with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as “applicable facilities,” while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments: “The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.” The SDT responded as follows: “The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.” In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.” PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.” We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. This SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1. 2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1 R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all “modelers,” the result will be outdated data in someone’s model, which can have a bad result. The team should have one broad “data sharing” policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)
Yes

Yes
Ingleside Cogeneration LP agrees that the explanation of the periodicity requirements are an improvement over previous versions.
Ingleside Cogeneration LP agrees that the ability for Transmission Planners to effectively model and simulate actual system response to frequency transients can lead to reliability improvements. In addition, the technical language used in the latest version of MOD-027-1 has been refined to an acceptable point in our view. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R2) must contain language that focuses on the strength of the validation process – not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed – even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
ATC recommends the following changes: 1. For Requirement 5, ATC recommends replacing the wording at the end of the requirement "that includes the following;" with "that includes how any of the following criteria are not met:" because the existing wording does not express that the criteria are not met when the model is not usable. 2. Attachment 1, Row 7, Verification Condition column – ATC agrees with the STD intention that base load units should be exempt because they are "not responsive to frequency excursion events". However, this insinuation of base load units is too vague. Therefore, ATC recommends additional wording to read "New or existing base loaded units are normally not responsive to a frequency excursion event". This makes it abundantly clear that this condition normally applies to base loaded units.
Individual
Ken Gardner
Alberta Electric System Operator
1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. 3. The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units. 4. Requirement R4, as written it appears owners of generating units that plan to change out the governor are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change.
Individual
Anthony Jablonski
ReliabilityFirst

ReliabilityFirst votes in the Negative for the draft MOD-027-1 standard since ReliabilityFirst believes there is a major disconnect/flaw between the Applicability Section (4.2. Facilities) and Requirement R2, part 2.1. This major flaw will create confusion on which generating units are required to be verified per the standard. ReliabilityFirst offers the following comments for consideration: 1. Requirements R2, Part 2.1 - There is a clear disconnect between the Applicability section of the standard (i.e. individual units/plants greater than 100MVA - Eastern or Quebec Interconnections) and Requirements R2, Part 2.1 which requires"… Verification of an individual unit less than 20 MVA." Based on the Applicability section, units less than 20 MVA are not applicable under this standard. Furthermore, units under 20 MVA do not fall under the NERC Statement of Compliance Registry Criteria as criteria for registration purposes for GOs and GOPs. 2.Applicability Section 4.2. Facilities – ReliabilityFirst thanks the SDT for their justification for the 100 MVA threshold, but still believes that the Applicability should be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). Even though the 100 MVA threshold covers 80% of the connected MVA or greater for each Interconnection (in aggregate), depending on the geographic location (within the BES), that value may be much less. For example, if there is a certain load pocket in which the majority of the connected generation is lest that 100 MVA, the dynamic models would not be required to be verified per this standard. Thus not having verified accurate dynamic models for this specific location could hinder the reliability of the BES. ReliabilityFirst recommends changing the Applicability section to be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES).
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
No
In Row 5, the use of 350 MVA as the cutoff for "sister unit" treatment is not reasonable. We propose the limit can be increased to 500 MVA without any adverse reliability impacts. Also, in Row 6, the allowable time for existing units to be verified following an indication of model problems should be 2 years, rather than 1 year, since existing legacy units may require additional resources to understand and resolve the issues.
1. In 4.2.1.2, the use of the term "directly connected at a common BES bus" suggests that wind farms are not applicable facilities, since wind generators are typically directly connected to a non-BES bus (e.g. 34.5 kv). We suggest that the applicability to wind farms be clarified more explicitly. 2. In R1, the present wording allows for the TP to provide only one of the three types of data, even if the GO requested all three. We suggest removing the wording, "one or more of". 3. In R1, the present requirement is for the TP to provide instructions to the GO on how to obtain the acceptable models and associated block diagrams and data. We believe that since the TP is very familiar with this data and the GO may not be, it is far simpler and efficient for the TP to provide the actual data on request, not just the instructions on how to obtain it. 4. In R2.1.1, the GO is required to have documentation comparing the "model response" to the "recorded response", in this case MW vs. frequency. First, to determine the model response requires the ability to run dynamic studies. Generally the GO does not have the simulation capability or the subject matter experts required to perform dynamic system studies. It would seem that the intent of this requirement is that the GO must expend considerable resources to gain this capability, either internally or by other means. Is this the intent of the SDT? 5. In R3, the requirements for the written response to the TP need clarification. The term "either" would suggest there are two possible responses. However, there appear to be three possible responses. We suggest there needs to be a 4th possible response option for the GO, for the GO to initiate contact with the TP to schedule a meeting to discuss the technical issues with the model. The necessary collaboration between the GO and TP to understand the model deficiencies will require time, thus may require more than the 90 days to reconcile the model issues. 120 days is suggested. 6. There is a document problem with the first sentence in R4. 7. In Section 5 Effective Dates: The considerable time and resources needed to get up to speed with model verification suggests there needs to be more time allowed in the earlier phases of the compliance timeline. We suggest using 20 percent in 4 years, 40 percent in 6 years, and 100 percent in 10 years.
Individual
Thad Ness
American Electric Power
Yes
Yes
1) In Section 4.2.3, the first line should read "Generation *in* the…". 2) In Section 5.3, the word "thirty" should be removed from the end of the fourth line. 3) In Section B, Requirement R2 contains bold faced text stating "Error! Bookmark not defined.", is this a mistake? 4) MOD-027-1 R5 ends with "...that includes the following:" yet

whatever the SDT intended to follow is missing. Please note that subparts 1 through 3 are referenced in parenthetical statements within the respective requirements and that it does not make sense that these subpart criteria are also what needs to follow "...that includes the following:"
Individual
Michael Falvo
Independent Electricity System Operator
No
Attachment 1 Row 7 leaves the impression responding to frequency excursion is merely a choice and this impression is harmful to reliability. Few "applicable units" should be unresponsive to over and under frequency excursions. If Generator Owners can choose to not help regulate frequency by simply notifying the Transmission Planner, why would any Generator Owner continue to regulate frequency? The attachment should be changed so units are unresponsive to frequency excursions only under conditions accepted by the Transmission Planner.
No
The long periods in Attachment 1 introduce too much risk to modeling assumptions used to assess transmission system reliability and to make other operating and planning decisions which do not reflect or address the actual performance of the system and equipment. This standard should not only establish the maximum period that Transmission Planners and Generator Owners to complete tasks but also to require the Transmission Planners to establish more stringent requirements when necessary to reduce the risk to reliability to an acceptable level. In some jurisdictions, e.g., Ontario, Generator Owners have 30 days to transmit the verified model, documentation and data to the Transmission Planner. Generator Owners are also required to indicate immediately following testing whether the installed equipment performed as expected. This approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet connection requirements. Emerging from this process is the Generator Owner's conditional right to connect provided he meets an obligation to demonstrate the installed equipment behaves as well as assumed during the assessment process. In this way, the risk to reliability is reduced to an acceptable level as the exposure of the decision making process to flawed modeling assumptions is minimized
a. All references to "real" power should be changed to "active" power to follow SI standard practice. b. One serious weakness is no there are explicit NERC performance requirements for frequency regulation. In some jurisdiction, e.g., Ontario, generating units are required to materially help regulate the frequency as the Transmission Planner sets performance requirements for droop, deadband and speed of response. All forms of generation are required to help regulate frequency to the extent practicable. For example, solar installations are required to reduce output during over frequency excursions. This standard in its present form allows "applicable units" to continue to not help regulate frequency could expose the BES to reliability risks. c. In Ontario, experience has been the models typically used by the Transmission Planner are not commonly employed by Generator Owners. The standard recognizes this in R1 by giving the obligation to the Transmission Planner to provide model block diagrams or data sheets to the Generator Owner. As the Transmission Planner may be unaware of practicable constraints on a unit and the Generator Owner may not be familiar with the reliability models, both parties must reach an accommodation on the details to verify the model. R2 should be changed so the Generator Owner is required to provide a model that has been verified by a method accepted by the Transmission Planner. If the Transmission Planner requires verification only with ambient measurements, then the Generator owner should be required to do verification in this way. This concept that the Transmission Planner should decide whether submissions it receives are suitable should permeate this standard. d. R2.1 should be amended (see below) to add flexibility to include other practical combinations of units to be used for verification. For example, it can be more practicable to test wind and solar installation one feeder at a time but this is not allowable with the standard in its present form. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA (gross nameplate rating) may be performed using either an individual unit, a combination of units, or plant aggregate model(s). e. In Ontario, we face resistance to our standards that exceed NERC requirements. It will be very helpful if the SDT in its response offers its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, we would appreciate responses such as: "In the opinion of the SDT, having more applicable units on closed loop voltage control, reducing the time to transmit verified information to the Transmission Planner, having specific excitation performance requirements, expanding verified information to include limiters and other devices that affect excitation system performance, and making the requirements in this standard applicable to wider range of equipment are all practices that will tend to improve reliability." or "In the opinion of the SDT, the requirements in this standard are not intended to preclude continuing or implementing more stringent Transmission Planner requirements." This type of response would help us to continue to augment the continent-wide standard with additional requirements to maintain reliability in our part of the interconnection. f. We appreciate the SDT's effort to implement our proposed language changes to remove a potential conflict with the Ontario regulatory practice respecting the effective date of implementing approved standards. The added language, unfortunately, was not added at the appropriate places. We suggest the SDT to move the wording ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," in Section 5.1 to right after "approved by applicable regulatory approval", and move that same wording to right after "following applicable regulatory

approval" in Sections 5.2 to 5.4. Also, the same phrase should be appended to each of the four bullets in the Section "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after "following applicable regulatory approval."
Group
Southern Company
Shammara Hasty
Yes
Yes
Southern Company agrees with the modifications to Attachment 1 (the Periodicity Table) as they both simplify and clarify the periodicity.
The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 8 of Attachment 1 to be deleted. Requirement R4 has a problem with the bookmark "Error! Bookmark not defined". We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location.
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 8 should be a part of Applicability section 4.2 Facilities. The reader of the standard shouldn't have to get to the last row of an attachment to determine as to whether a unit is exempt or not.
1.FE believes that Requirement 5 in an un-necessary requirement that the Transmission Planner must respond within 90 calendar days that the model is usable. The Transmission Planner should only respond if the information is not usable. We suggest that this requirement should be in a negative perspective and offer the following revision: R5. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 5.1 through 5.5), and shall include a technical description if the model is not usable that includes (but not limited to) the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 5.1. The turbine/governor and load control or active power frequency control function model fails to to compute modeling data without error along with suggested areas for investigation, 5.2. A listing of parameters that fail the Transmission Planner's data checks, 5.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 5.4. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria. 5.5. The turbine/governor and load control or active power/frequency control model submitted by the Generator Owner is either a user defined model or a model that is not acceptable for use in the Transmission Planner's Regional Reliability Organization footprint
Individual
Wryan Feil
Northeast Utilities
Yes
Yes
No Comments
Individual
Brian Evans-Mongeon

Utility Services
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Dominion
Mike Garton
Yes
Yes
There appears to be a mismatch between Requirement R2 and the Effective Date statements. Specifically, R2 is applied on an “applicable unit” bases where the Effective Date statements are applied on an “applicable unit gross MVA” basis. R4; bookmark #4 in the clean version needs to be corrected, shows ‘Error! Bookmark not defined.
Group
Seattle City Light
paul haase
Requirement 2.1.1 states three separate ways to verify MW response for a synchronous generator, but uses the term "either of" when refering to the choice of tests, which implies two tests. Please clarify with either two tests or change the reference to "any of." In addition, one of the tests of 2.1.1 includes a partial load rejection. Such a test is already part of the Kestrel test procedures currently performed by Seattle City Light. It is not clear from the requirement and footnote if our existing test would be sufficient for validation or if the other two tests would also be required. Please clarify the language of R2.1.1.
Individual
John Martinsen
Snohomish County PUD No.1
Agree
Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Individual
Mike Hirst
Cogentrix Energy
1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1. Take for example a combined cycle plant with the CTs at base load output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc. may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to “real power

response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW set point or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or Page 7 of 11 removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in comment #1 above. 3. There is presently no definition of how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. . 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid over speed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper "Testing Methods, An Overview," states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Page 8 of 11 Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in comment #1 above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, "Differences between the control mode tested and the final simulation model must be identified," and "some method of accounting for these differences must be presented," are too vague and constitute no solution at all. It would be better to just admit that trip testing can't get the job done. 6. The instruction in R4 to notify the TP, "within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control," is too vague, despite the attempted clarification in footnote #5, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. Would an output power restriction due to a broken coal feeder belt be reportable, for example? 7. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 8 of Attachment 1 to be deleted. 8. We

recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location.
Individual
Daniel Duff
Liberty Electric Power LLC
Agree
NAGF
Group
Duke Energy
Greg Rowland
Yes
Yes
We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units is independent of the physical location.
Group
MEAG Power
E Scott Miller
Agree
Southern Company Services, Inc. - Gen
Individual
Eric Salsbury
Consumers Energy
No
Consumers' previous comments - The generator model with the excitation system and the load rejection testing or frequency step response testing is difficult to perform and has possibilities of damaging equipment and causing reliability issues on the system in order to perform. Previous SDT reply - The GVSDT thanks you for your comment. MOD-027 is written to allow for the use of ambient monitoring, recorded data associated with the normal operation of your equipment. A GO with your concerns can alleviate the issues you mention using ambient monitoring. While we agree with the reply by the SDT when ambient monitoring is available, it is not available on all of our equipment. Therefore, we stand by our previous comments.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power System Planning agrees with the revisions made to Attachment 1.
Yes

Idaho Power System Planning agrees with the revisions made to Attachment 1.
Attachment 1 – Note 1 Idaho Power System Planning comments Attachment 1 discusses unit model verification to a frequency excursion using a recorded response from the generating unit. Attachment 1, Note 1 defines the frequency deviation criteria. Idaho Power System Planning asks the GVSDT to include the minimum acceptable data sampling criteria of the recording equipment as part of the Note 1 criteria. Requiring each Transmission Planner to maintain a list of acceptable models, and then requiring Generator Owners to submit data according to those models is unreasonable. The list of acceptable models needs to be at least regional, if not continent-wide. In addition, some required longevity needs to be specified to allow Generator Owners to appropriately plan and perform the verification work.
Group
JEA
Thomas McElhinney
JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Individual
Kirit Shah
Ameren
No
We believe that there is a discrepancy between the language in the requirement and VSL for R4 and Row 4 of the Attachment 1. In the requirement, a 180 day period is stated, while in Row 4 of Attachment 1, a 365 day period is stated.
Yes
(1)As a general comment, NERC should make all the papers listed in the references section of the standard readily available on their website. (2)There appears to be an extra word "thirty" in both redline and clean versions of the standard under section 5.3 of the Effective Date section of the draft standard. (3)As we understand, part of R1 is for the Transmission Planner to provide instructions on how to obtain the list of acceptable model types for use in dynamic simulations. In this regard, we ask the SDT if this would preclude the use of user-written models? (4)We still have serious concerns about compliance with new MOD-027-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect as explained in our response to draft MOD-026-1. We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal requirements within MOD-026 and MOD-027. This will synchronize the reporting and verification requirements and help minimize the resource burden of compliance with both efforts. At the same time it will create consistency across the country.
Individual
John Yale
Chelan PUD
Yes
Yes
Note 2, Page 4: It is unclear what would constitute and acceptable accounting - "Some method of accounting for these differences must be presented..." Unless any accounting would be acceptable, suggest some guidance.
Individual
Maggy Powell
Exelon Corporation and its affiliates
Yes
Yes

1. Exelon previously commented that MOD-027-1 R5 implies that it is the Generator Owner's responsibility to ensure that the model is "useable" based on the criteria specified in Parts 5.1 through 5.3; however, it is at the discretion of the Transmission Planner. As written, the requirement gives the Transmission Planner the discretion to reject the model based on governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09. Exelon again reiterates that the usability of the model should not be confused with a model that accurately represents the generating unit governor and provides projected results. 2. Please confirm that the number of generating units combined into the percentage for implementation of unit verification includes those generating units that may have a documented exclusion such as an existing unit that does not have an installed control system. 3. MOD-027-1 R4 appears to have a formatting issue – the statement "Error! Bookmark not defined" is in bold letters within the requirement.
Individual
Teresa Czyz
Georgia Transmission Corp.
Yes
Yes
Group
Luminant
Brenda Hampton
Yes
No
While Luminant agrees with the concepts in the periodicity requirements in Attachment 1, it would be beneficial for the drafting team to clearly identify that units that are base load (row 7) are excluded from model verification.
Individual
Don Jones
Texas Reliability Entity
1) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is “directly connected” to the BES. Please consider reviewing the language to see if it should instead say “included in” the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not “directly connected” to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. 2) Requirement R4: Suggest removing the phrase “or plans . . .” and rewording as “Each Generator Owner shall provide revised model data for each applicable unit . . ..” There appears to be a footnote error here – delete “6”? 3) TRE recommends changing to “Planning Authority or Transmission Planner” in the Functional Entities in Section 4.1.2 instead of “Transmission Planner”. This change should be duplicated in the requirements. The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
No
(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 3 provides guidance for early compliance and we agree that early compliance should be allowable. It establishes that 10 year period begins from the transmittal date. If a GO has data that satisfies the early compliance condition for a verified model and that data is a five years old, the Note would appear to allow the GO to transmit the data to the TP and receive credit for next 10 years effectively creating an initial 15-year re-verification cycle. Is this intended? If not, please provide more guidance for how soon the GO would have to re-verify its model. (2) Row 4 in Attachment 1 states

that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new turbine/governor and load control or active power/frequency control equipment control system. However, Requirement R4 also applies to changes to the same control system. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. (3) Per Requirement R4 and Row 6 in attachment 1, the GO has 180 days to submit a plan to Transmission Planner to verify the model and then another 365 days to perform the model verification date. That would appear to give the GO approximately a year and half to complete the verification for changes (including replacement) to the control system. Requirement R2 and Row 4 appear to require completion of the verification in 365 days or a year. Please modify the table or requirement to clarify appropriate application.
(1) Thank you for modifying the applicability section. It is greatly improved and is much clearer than the previous version. However, we believe there are a few additional minor refinements necessary. First, generators can be and are part of the Bulk Electric System. Thus, we suggest changing "Facilities that are directly connected to the Bulk Electric System (BES)" to "generation Facilities that are part of the Bulk Electric System." Otherwise, there might be some confusion if the drafting team intends to draw in generators that are not part of the BES. Second, we find the wording "will be collectively referred as an 'applicable unit' that meet the following" confusing. We think the intent was to clarify that an applicable unit is one that is part of the BES and meets criteria established in section 4.2.1, 4.2.2, and 4.2.3. However, we think the inclusion of the "will be collectively referred as an 'applicable unit'" is superfluous. Because the section is the applicability section, we think this language could be struck for clarity and the applicable units will be understood to mean those that meet the criteria in section 4.2. As an alternative, the drafting team could explain in a footnote what they mean by the term applicable unit. Third, with the two proposed changes, we think the final wording of section 4.2 after the opening clause should be "generation Facilities that are part of the Bulk Electric System (BES) that meet the following criteria:". (2) In requirement R2, please change "for each applicable unit" to "for each of its applicable units." This is the previous wording and is more correct. The current wording literally says that the GO must provide a verified model for each applicable unit including those it does not own. After all any unit that meets applicability criteria including those owned by other GOs would be an applicable unit. (3) Please specify in M1 that a Transmission Planner may also provide an attestation that no such request was received if this is the case. Use of an attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set in the use of attestations in measures in FAC-003-2 M1 and M2. (4) We continue to believe that the examples provided in the comment form should be included in the standard. Please create an Application Guidelines or Guidelines and Technical Basis section in the standard and add them. This has become common practice with developing standards. We do not understand why the drafting team would not want to retain such information that helps readers understand the standard and that has already been developed. Furthermore, it would make it easier for commenters to see what has changed in the examples because a red-line of the standard is required. Because the examples were contained in the comment form this time and during the previous posting, it is not easy to deduce the changes because there is no red-line. If the examples are not included in the standard, please provide more explanation than was provided during the last response to comments which was that it is not appropriate to include the examples. We do not understand why it is not appropriate. (5) We disagree with the need to retain the latest model verification evidence under Requirement R2 and M2. First, this is not consistent with the Section 3.1.4.2 of Appendix 3c to the NERC Rules of Procedure section which states that the audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since the audit cycle for a GO is six years and the model verification period is 10 years, the GO will have to retain data past its prior audit period. Furthermore, the auditor will have already had an opportunity to review the model verification data during the last audit. Presumably, if they did not find any compliance violations, there should not be a need to review this data again. Thus, the data retention should not exceed the six year audit cycle. (6) How will mothballed units be handled in Attachment 1? If a mothballed unit is returned to service which row in Attachment 1 applies? What if the unit was mothballed before the effective date and returned to service after all stages of the effective dates? What if it was mothballed after an initial verification? How does this affect the next verification date?
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
Why wouldn't the GVSDT just identify (i.e. show reference note on Attachment 1 table) that "Applicable units does not include units that don't respond to frequency excursions (e.g. base-loaded units)"?
In trying to follow the flow of this standard, it is obvious that R1 precedes R2 logically. But then it also appears that possibly R5 actually takes place before R3. There does not seem to be any requirement for the Transmission Planner to provide Written Comments to the GO that address the second and third bullet points of R3. It seems that a requirement should be added for the TP to provide written comments for any of the 3 bullets shown in R3; however, only the first bullet of R3 has been required of the TP (in R5) as the standard is currently written in Draft 3. The first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a

GO has identical equipment at different physical locations, they are equivalent. Equivalency of units should be independent of the physical location. Other minor edits: • In A.5.1 for the Effective Date, it should say R3 through R5 (not R6, as there is no R6). • Also, by footnote 4 on R4, there appears to be some sort of "Error! Bookmark" from when the footnotes were changed. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1. Take for example a combined cycle plant with the CTs at baseload output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to "real power response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW setpoint or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the generator modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in our comments above. There is presently no definition of how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid overspeed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper "Testing Methods, An

Overview," states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in our comments above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, "Differences between the control mode tested and the final simulation model must be identified," and "some method of accounting for these differences must be presented," are too vague and constitute no solution at all. It would be better to just admit that trip testing can't get the job done. The instruction in R4 to notify the TP, "within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control," is too vague, despite the attempted clarification in footnote #5, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. Would an output power restriction due to a broken coal feeder belt be reportable, for example?
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No comments on the question.
No
No comments on this question.
A stated purpose of Generator Verification is "to ensure that generator models accurately reflect the generator's capabilities and operating characteristics." Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets' capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load's process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load's production schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Darryl Curtis
Oncor Electric Delivery Company
No
Oncor does not support the position that the Transmission Planner (TP) is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the Planning Authority (PA) only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
No
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive

generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Individual
Russell Noble
Cowlitz PUD
No
Cowlitz supports the comments of the NAGF SRT: 1. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 8 of Attachment 1 to be deleted.
Yes
Cowlitz supports the comments from the NAGF SRT: 1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1. Take for example a combined cycle plant with the CTs at base load output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc. may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to "real power response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW set point or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised orremoved [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in comment #1 above. 3. There is presently no definition of how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting

whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the TransmissionPlanner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. . 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid over speed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper "Testing Methods, An Overview," states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in comment #1 above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, "Differences between the control mode tested and the final simulation model must be identified," and "some method of accounting for these differences must be presented," are too vague and constitute no solution at all. It would be better to just admit that trip testing can't get the job done. 6. The instruction in R4 to notify the TP, "within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control," is too vague, despite the attempted clarification in footnote #5, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. Would an output power restriction due to a broken coal feeder belt be reportable, for example? 7. We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location.
Individual
Don Schmit
Nebraska Public Power District
Agree
MRO NSRF

Kathleen Goodman
ISO-New England
Yes
Kathleen Goodman
ISO-New England
No
Attachment 1, Row 4 allows for transmission of a verified model 365 days after commissioning of a new generator. This is an unacceptable length of time for a generator to be on-line from both a reliability standpoint and this length of time is in conflict with ISO/RTO Standard Generator Interconnection Agreement language. The ISO/RTO Standard Generator Interconnection language requires Generator Owners to provide verified models ***prior to*** Commercial Operation.
Kathleen Goodman
ISO-New England
Attachment 1, Row 8 has a reference to capacity factor. The capacity factor section has been removed from the body of the standard. If the capacity factor is still part of the standard by it's existence in the Attachment then this is unacceptable. Older large units with low capacity factors will be called upon to operate during extreme weather events when the system is most stressed. System reliability will be compromised if the modeled characteristics of the units differ from what is actually installed in the field.

Requirement R1 may bring out some concern over the copyrighted models supplied by the simulation software vendors. Hopefully this can be worked out with the vendors.

Requirement R3 might only require a “written response” from a Generator Owner to the Transmission Planners notification that a model is not useable with some technical basis for keeping the current model that is not usable. Wording must be included so that ultimately the Generator Owner shall provide a “usable model” to the Transmission Planner.

Requirement R5 sub-requirement wording should be changed to indicate the Transmission Planner shall notify the Generator Owner if the excitation model does not initialize, a no-disturbance simulation results in transients or a disturbance simulation results in a model exhibiting negative damping.

Individual or group. (47 Responses)
Organization (29 Responses)
Group Name (18 Responses)
Lead Contact (18 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (10 Responses)
Comments (47 Responses)
Question 1 (29 Responses)
Question 1 Comments (37 Responses)
Question 2 (29 Responses)
Question 2 Comments (37 Responses)
Question 3 (0 Responses)
Question 3 Comments (37 Responses)

Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
Yes
R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1 (i.e. there is not a relay that stands behind every limiter). Section 1.1.2 should be struck – as this is covered under the direction of other standards such as EOP-003. The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. This is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. The term “blackstart unit material” in applicability para. 4.2.4 (p.2) is not understood. We suggest that the SDT remove the term “blackstart unit material” or clarify when a blackstart unit designated as part of the Transmission Operator’s restoration plan would be immaterial. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in a Generator’s possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable. PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Group
Northeast Power Coordinating Council
Guy Zito
Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.

Group
Pepco Holdings Inc and Affiliates
David Thorne
Yes
Yes
Attachment 1 and Attachment 2 have been revised since the last draft. In these latest set of attachments, although the Zone 2 loss of field characteristic has been set to operate prior to the Steady State Stability Limit (SSSL) is reached, it is also set so that it would operate prior to the generator capability curve being exceeded. This appears to be in conflict with the intent of the standard to ensure that protection should not operate before the equipment capability is exceeded. The Zone 2 characteristic should properly be set between the Generator Capability Curve and the Steady State Stability Limit. As such, Figures A.6 and A.7 in IEEE C37.102-2006 might be better coordination examples to use for these attachments.
Individual
Delmarva Power & Light Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
Atlantic City Electric Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
Potomac Electric Power Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
TransAlta Centralia Generation LLC
Yes
Yes
N/A
Individual
Manitoba Hydro
Yes
None.
Yes
None.
R1 - Manitoba Hydro finds the wording ‘At a maximum of every five calendar years’ awkward. We suggest changing the wording to read ‘at least once every five calendar years’. R1.1.2 - Manitoba Hydro suggests deleting R1.1.2 which reads, “The applicable in-service Protection System devices are set to operate, isolate or de-energize equipment, in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits”. Since these are fundamental functions of any protection system device, there is no need to include this in the NERC standard. R1.1.1 - Is AVR defined somewhere? We could not find its definition in the Glossary. General Comments - 1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?. 2. The concept of equivalent unit testing should be applied to both synchronous condensers and generators. Equivalent units are addressed in Row 5 of MOD-027-1 Attachment 1, but it is not clear if this attachment applies to PRC-019. We would suggest that “Attachment 1” from MOD-027-1 be added to all of the standards included in this project. 3. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled “Consideration for early Compliance” with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar

language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1).
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
Regarding the "Functional Entities" listed in the Applicability Section, it is not clear how PRC-019 can only apply to TOs that own synchronous condensers because R1 & R2 require GOs to communicate with TOs regarding the generation equipment subject to the standard (units over 20 MVA, units connected at a common bus with total generation over 75 MVA, and blackstart units in the TOPs restoration plan). Regarding the "Facilities" listed in the Applicability section, BPA believes that Section 4.2.4 should apply to blackstart units designated as part of a TOP's restoration plan. The phrase "material to and designated as part of" the restoration plan creates ambiguity and would seem to require TOPs & GOs to agree on which generators are "material to" the blackstart plan. R2 is designated as a Long-Term Planning standard, but appears to allow coordination within 90 days following the implementation of setting changes. The phrase "Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1," is not clear. R1 requires coordination at least once every five years. R2 should require coordination before implementation of system, equipment, or setting changes, not within 90 days after.
Group
pacificorp
ryan millard
Yes
Yes
Individual
PSEG
Yes
Yes
We voted "Negative" on this standard the reasons shown below: This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1. 1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a "team" with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as "applicable facilities," while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments: "The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states "Synchronous condensers are not currently addressed in the NERC Registry Criteria" However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency." The SDT responded as follows: "The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model." In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: "The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2." PRC-019-1: "The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers." We need to see "one" statement from the SDT on the inclusion or exclusion of synchronous condensers that makes

sense technically, and soon. 2.No reliability benefit has been demonstrated for having the coordination review required by R1 done every five years. We suggest that the R1 be modified so that it's clear that the entities must "verify" coordination upon the effective date ONLY, but not every 5 years thereafter. The effective date Section 5, part 5.1.1 states "By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities." Therefore, we suggest that R1 be rewritten as follows: "BY ITS EFFECTIVE DATE IN SECTION 5, each Generator Owner and Transmission Owner with applicable Facilities shall VERIFY the COORDINATION OF the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions."
Individual
Xcel Energy
Yes
Yes
Individual
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)
Yes
Yes
Ingleside Cogeneration LP agrees that the proper coordination between a generator's voltage limiters, protective relay settings, and its stability limits can best assure its availability in response to transient conditions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring assessments (R1) must contain language that focuses on the strength of the validation process – not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed – even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects.
Individual
American Transmission Company
Yes
Yes
Individual
American Electric Power
Yes
Yes

Individual
Wisconsin Electric Power Company
Yes
Yes
1. In R1.1.2, we suggest revising the sentence to : “The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage…”. 2. In R1, there needs to be a way for entities to take credit for coordination studies done in the last 2 years prior to the effective date of this standard. 3. In R2, the 90 day requirement to document coordination following a change is not reasonable. It may not be possible to obtain the necessary information from equipment vendors in this timeframe. We suggest a time of 180 days for this requirement. 4. It is not clear how these requirements would be satisfied at wind farms. None of the example information in Section G Reference appears to be applicable to wind farm equipment. We suggest that wind resources be specifically exempted from this standard.
Individual
Independent Electricity System Operator
Yes
Yes
1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by: a. In the Implementation Plan, under the Section “In those jurisdictions where regulatory approval is required:”, adding a phrase “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities,” right after “following applicable regulatory approval” and before “each Generator Owner…” b. In Section A5.1 of the standard, adding the same phrase “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities,” right after “following applicable regulatory approval” and before “each Generator Owner…”. 2. The wording of R1 is confusing, since the required coordination shall be maintain all the time. We suggest a change of the wording as follows: the phrase “At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls” should read “At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall review the coordination of the voltage regulating system controls” ; Also, the phrase “1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.” should read” 1.1.1. The in-service voltage regulating control limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.”
Individual
New York Power Authority
Yes
Yes
This Standard does not bring added reliability for the Bulk Electric System; it only adds an administrative burden for the entities. NYPA in its current protection system relay settings process inherently takes into account a margin for a unit’s in-service limiters as well as other typical performance parameters.
Group
Tennessee Valley Authority
Brandy Spraker
1. Reference, Examples of Coordination, page 7 of 11, bullets at the top of page 7, Recommend deleting the word “associated” in all of the applicable bullets. Justification is that the word “associated” is not needed in these bullets and it will make the bullets more crisp. 2. Standard, 4.2 Facilities, The unit size applicability for PRC-019-1 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027-1 (i.e. MOD-026-1 Draft, 4.2,

Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ... (including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ... (including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ... (including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.) 3. Requirement R1, Recommend changing the periodicity of this verification as stated "At a maximum of every five calendar years, ... " to a recommended verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, "6 calendar years." Justification is to coordinate protective system relay testing during plant outages with the voltage regulating controls and protections testing that can be performed during outage shut-down or start-up sequences.
Group
Southern Company
Shammara Hasty
Yes
Yes
Please consider placing the applicable unit size for PRC-019 and MOD-025 equivalent to that specified by MOD-026 and MOD-027. The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. We suggest striking "Convertor Overtemperature" from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. R2 specifies "perform the coordination" while M2 states "coordination review" – we believe that R2 should be changed to "review the coordination" R1 appears to have been written with evolving T&D systems in mind. It should be made clear that all that is required for a generation unit that has experienced no changes affecting the response in question is a review of the equipment state every 6 (six) years rather than requiring a new coordination study.
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Individual
Northeast Utilites
Yes
Yes
No Comments
Individual
Utility Services
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Dominion

Mike Garton
Yes
Yes
Group
seattle city light
paul haase
No
New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Individual
Omaha Public Power District
Yes
Yes
We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Individual
Liberty Electric Power LLC
Agree
NAGF
Individual
Snohomish County PUD No.1
Agree
Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Individual
Cogentrix Energy
1. R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, 2. It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1. 3. The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. That is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. 4. The term “black start unit material” in applicability para. 4.2.4 (p.2) is not understood. We would object if the intent was to designate any unit that has the potential for black startcapable conversion, in addition to units that are presently black start resources. GOs would in this

case have to take on substantial burdens based on mere conjecture as to modifications that might (but probably would not) be made sometime in the future. 5. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in our possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable. PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. 6. The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. 7. It is suggested to strike "Convertor Over temperature" from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not an element that can be coordinated. 8. R2 specifies "perform the coordination" while M2 states "coordination review" – we suggest that R2 be changed to "review the coordination"
Group
Florida Municipal Power Agency
Frank Gaffney
1) R1 can be misinterpreted to require a full-blown coordination study every 5 years even if nothing at the plant had changed. There should be a qualifier saying that past coordination studies are still valid if nothing has changed, but that at minimum a review is needed every 5 years to see if the existing coordination study is still valid. 2) A synchronous condenser can be owned by either a TO or GO. For instance, there are installation of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO who owns a synchronous condenser.
Group
Duke Energy
Greg Rowland
Yes
Yes
1) Section 1.1: Reword to clarify "normal" is describing the AVR control mode only. Also, SDT should consider mentioning weak system operating conditions are typically used when coordination with the SSSL. Suggested rewording: "Under steady-state system operating conditions, and assuming normal AVR control loop conditions, verify the following coordination items for each applicable Facility:" 2) Section 1.1.2: Strike this section, as it is outside the scope of this document. It appears to be mandating protection. PRC-019-1 should be focused on settings. 3) Page 7/11: (Reword 2nd paragraph) Examples of limits, limiters, protection which must be coordinated if employed include: 4) Page 7/11: Remove all the words "associated" in second paragraph. 5) Page 7/11: Remove section on SSSL calculation. Does not belong in standard, see references listed as needed. 6) The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. 7) The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. 8) Strike "Convertor Overtemperature" from this list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. 9) R2 specifies "perform the coordination" while M2 states "coordination review" – we believe that R2 and M2 should be consistent.
Individual
Indiana Municipal Power Agency
Agree
Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum for PRC-019.
Group
MEAG Power

E Scott Miller
Agree
Southern Company Services, Inc. - Gen
Individual
South Carolina Electric and Gas
Yes
Yes
Group
JEA
Thomas McElhinney
JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Individual
Ameren
Yes
No
(1)Although we prefer a % of Facilities approach, we can accept the R1 VSL revision with the stated time frames. (2)A time-based VSL does not align with the severity of failing to meet R2. The severity is primarily a function of the amount of on-line exposure. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. We request that for R2 the SDT replace the time-based (days late) with % of MWh during the period of violation to more properly account for aggregate impact and restate the R2 VSL as follows: (a)Lower VSL becomes 'The Generator Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing from 0% to 5% of their total MWh generated during the violation period.' This does require each unit to be coordinated. (b)Moderate VSL becomes '…more than 5% and less than 10%' (c)High VSL becomes '…more than 10% and less than 15%'(d)Severe VSL becomes '… more than 15%'. (3)We request that the SDT insert 'latter of' before 'identification or implementation' in R2 VSL if the SDT does retain the time-based VSL format. Identification differs from implementation so clarity is needed if a violation does occur.
(1)R2 is unclear as written, please insert 'latter of' before 'identification or implementation' to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. (2)Attachment 1 Example appears to violate R1 1.1.2. Loss of Field Zone 2 trips before 'operating conditions exceed equipment capabilities.' On the other hand, it would certainly 'limit the extent of damage when operating conditions exceed equipment capabilities or stability limits' since it trips before either of them are reached. This example does show how specialized and complex this coordination is. Entities may have different margins, asset protection, and operating practices. We presume the SDT intends that the examples show 'coordinated' capabilities, controls, and protection. If not, the lack of coordination should be pointed out. (3)We request that the GVSDT make all the papers listed in the reference section of the standard readily available on the NERC website.
Individual
Exelon Corporation and its affiliates
Yes
Yes
Section D, "Compliance," Part 1.2, "Evidence Retention," (page 4 of 11) first paragraph is unnecessary and redundant since the retention periods specified are for a six year time period which would be the maximum time between compliance audits for a registered entity. Exelon suggests that this paragraph be deleted in its entirety.

Group
Luminant
Brenda Hampton
Yes
Yes
Luminant recommends that Requirement R1 and Measure M1 be revised to clarify that the coordination described in the text is not between the Generator Operator and Transmission Operator. R1 would be revised in the following manner, “At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service 1imiters and protection functions) with its applicable equipment capabilities and settings of the applicable Protection System devices and functions. 1.1. Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility”. Measure M1 would be altered in the same manner.
Individual
Texas Reliability Entity
Yes
Yes
1) Does the SDT foresee any conflicts between the proposed language in PRC-019-1 and the proposed setting limits in PRC-025-1, Generator Loadability? 2) The SDT may want to include a reference ANSI C50.13-2005 for proper coordination of the over/under excitation limiters with AVR, equipment capabilities, and loss-of-field, and other protective functions. 3) Measure M1: Evidence should also include documentation that actual settings for relays, AVRs, and limiters match the coordination study. 4) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is “directly connected” to the BES. Please consider reviewing the language to see if it should instead say “included in” the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not “directly connected” to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. 5) In general, the Protection System changes should be coordinated before energization (or re-energization) following a change. Is the 90 day time period in R2 consistent with the expectations of PRC-001?
Individual
City of Redding
Agree
SMUD/BANC
Individual
SMUD
SMUD strongly suggests the SDT align the proposed PRC standard with NERC’s current direction of migrating reliability standards to a Results Based Standards (RBS) and internal controls approach. This standard, along with all the other recent NERC PRC proposed standards, are vastly increasing the administrative effort by asking for more documentation of relay settings. For instance, in R1.1.2 – Is it really necessary to have a regulatory requirement for the GO to protect his own generator from damage? (Intentional Space.....) As an alternate approach, why not state that anytime a generator trips off by a protective function that must be set to coordinate with a limiter, the GO must demonstrate that the relay was set per this standard. That is, that the protective function did(emphasis added) coordinate with the limiters. If it is set correctly, there is no violation. If not, violation. This reduces the compliance burden significantly, but does not weaken the incentive to comply. Entities will want to ensure they set their relays per the standard because no one wants to cause an outage or get a violation. But no entity needs to spend time on pre-event, zero-defect, compliance documentation for all its units – only post event documentation is necessary for units that tripped. We feel this type of results based approach is a better choice for this standard.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery, NERC Reliability Compliance Coordinator

No
AECI does not believe R1 should exist as currently drafted, see below.
Yes
Applicability, Part 4.2.4, CHANGE: Remove this entire clause specific to Blackstart of units of any size, RATIONALE: AECI agrees with earlier Industry commenters that opposed the inclusion of these units and disagrees with the SDT's persistent inclusion. Inclusion of Blackstart units of any size, ultimately harms the grid reliability by imposing more regulatory-risk exposure upon them, such that our industry is already seeing many disappear from system restoration plans. With this trend left unchecked, and we are trying to piece our systems back together 10 years from now for whatever reason, the RCs will not even know that many of these viable units still exist. Many may have in fact been driven from existence by such well-intentioned laws having failed to consider the unintended consequences. In addition, the value of AVR functionality for Blackstart units is highly questionable during blackstart situations. Requirement R1, CHANGE: Redraft the language toward each responsible entity's internal controls program, RATIONALE: While AECI appreciates the initial 5-year time-line to "check the coordination of all our unit's in-service limiting "stuff", we see the R1 5-year revisit of no added value. This is in contrast to the value of R2's invoking the correct triggering mechanism for events that would precipitate rechecking such protective systems and setting's coordination. AECI simply believes R1 to be overly prescriptive and its existence, as currently drafted, will destine it for future removal.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
Yes
(1) R1 should be modified to clarify that the GO or TO shall coordinate their applicable Facilities. While most readers would interpret the requirement to apply to the Facilities owned by the GO and TO, it simply does not say this. We recommend using "each GO and TO shall coordinate the voltage regulating system controls … applicable equipment capabilities of its applicable Facilities and the settings of the applicable Protection System devices and functions." (2) While we disagree with the inclusion of blackstart units in this standard, the previous wording was actually more correct and consistent with the Statement of Compliance Registry Criteria. Changing "Blackstart Resource" to "blackstart unit" only causes confusion and ambiguity. By definition a "Blackstart Resource" is a blackstart unit that is included in the Transmission Operator's restoration plan. Since the applicability section also states that the blackstart unit must be included in the TOP's restoration plan, it is not clear what was accomplished with changing Blackstart Resource to blackstart unit. It causes the reader to question what additional units are intended if they don't mean Blackstart Resource. Furthermore, it deviates from the wording in the Statement of Compliance Registry Criteria. This is contrary to the response that was provided to a comment by PSEG to change the language during the last posting. The response indicated that the "SDT feels it is best to retain the NERC wording without modification." We can find no other citation in the response to comments indicating a reason to change it. Please change blackstart unit back to Blackstart Resource. (3) In applicability sections 4.2.1 through 4.2.3, please change "directly connected to the BES" to "that are part of the BES". Per the BES definition, generation units can be and are part of the BES. Using "directly connected to the BES" could draw in a non-BES unit. (4) There is an extraneous comma in R2.
Individual
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Cowlitz PUD
No
Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
No
Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
Cowlitz supports the review performed by the NAGF SRT with modification: 1. Requirement R1 appears to have been written with ever-evolving T&D systems with multiple owners/planners in play where Protection System settings may require adjustment to assure proper operation. However, this is not the case for generation facilities

which remain relatively static under single management until system improvements are made. Further, it is unprecedented to require a scheduled reassessment of system control settings without cause. The Standard Requirement R1 appears to assume it necessary to review past coordination engineering work and resulting system control and Protection System settings for errors every five calendar years. We see no reliability return in such activity. Requirement R1 must be centered on first establishing that proper coordination engineering and resulting system control and Protection System settings have been completed, and documentation of such work is retained in a Generation Facility Control and Protection Manual. Requirement R2 then covers the cause for review – system improvements, equipment upgrades, new operation theory, etc. – that triggers a reassessment of the coordination engineering and if necessary a revision to the Generation Facility Control and Protection Manual. The only possible item that may merit a scheduled activity is to verify all settings have not inadvertently changed, and are in compliance with the current Generation Facility Control and Protection Manual. 2. The nonexclusive nature of the listing in section G is a concern regarding proof of compliance. That is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. 3. The term "black start unit material" in applicability para. 4.2.4 (p.2) should be changed to the NERC defined term Blackstart Resource. Further, (departing from NAGF SRT Comments with suggested SDT response) it must be understood that Blackstart Resources must involve coordination between the TOP and the GOP. The TOP is not allowed to unilaterally designate blackstart capable resources within their restoration plan. EOP-005-2 mandates this via Requirement R13.
Individual
Nebraska Public Power District
Agree
MRO NSRF

Consideration of Comments

Project 2007-09 Generator Verification
MOD-025-2

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to MOD-025-2. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 48 sets of comments, including comments from approximately 155 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

There were a number of non-substantive changes made to the standard. Those changes are both explained in the summary comments for each question and in the individual responses to comments under Questions 1, 2, and 3:

In general, the comments indicated that industry is supports Attachment 1 as posted in Draft 3 of MOD-025-2. In response to stakeholder comments several changes were made to provide consistent wording and clarity within and among Attachments 1 and 2.

Based on comments received the GVSDT determined that Note 3 of Attachment 1 added confusion and since it was not vital to Attachment 1 it was removed. Note 3 said "It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator. "

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Clarifications were made in the standard regarding treatment of units in long term reserve shutdown, coordination with the Transmission Operator for staged testing, and collection of data for ambient condition corrections. The GVSDT also clarified that the first verification must be a staged test.

The industry is generally supportive of the VSLs. As a result of stakeholder comments, clarifying edits were made to VSLs for Requirements R2 and R3 to provide wording consistent with the VSL for Requirement R1– this is non-substantive because the level was not changed.

The following note was added to the Effective Date section for clarity – “The verification percentage above is based on the number of applicable units owned.”

As a result of stakeholder comment, clarification was added to the Effective Date section regarding regulatory approval in Canada.

In response to stakeholder comments, the following non-substantive changes were made in Attachment 2:

1) A clarifying phrase was added to the header in the “last verification” column

2) A bullet point in the Summary of Verification that was intended to be removed during the last comment cycle and was not, has now been removed

3) The tap setting and voltage ratio wording were made consistent throughout Attachments 1 and 2.

Spelling and punctuation corrections:

- Footnote 2 – Corrected capitalization in Wind farm verification
- VSL Requirement R1 moderate - removed period
- Attachment 1
  - Periodicity for conducting a new verification - second to last paragraph corrected capitalization of the word “load”
  - Verification specification for applicability Facilities – Changed ‘shall’ to ‘will’
  - 4.1 - corrected capitalization of the word “load”
  - Renumbered Notes 4 and 5 due to deletion of Note 3
- Attachment 2 – Added missing arrow at point “F”

Minority Views:

- A minority of commenters requested a periodicity greater than five years. The GVSDT believes that the verification periodicity for Real Power and Reactive Power capability is appropriate at five year intervals and was addressed in previous comment periods. The GVSDT believes that stakeholder consensus has been achieved in this regard.

- A few entities submitted comments with regard to the use of engineering analysis in place of staged testing similar to comments submitted during previous postings. The GVSDT explained that engineering analysis could be appropriate in some cases, but not in place of staged testing because engineering analysis will not identify equipment problems and these equipment problems may not show up during normal operations.

- At least one entity suggested that nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with nuclear plant specific NRC operating license.

The GVSDT reaffirmed that challenging the plant's safety systems is not required by this standard. The standard does not require operating beyond plant operating limits.

[SC1]

Index to Questions, Comments, and Responses

1. The GVSDT has revised attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below. 13

2. The GVSDT has revised the VSLs based on stakeholder comments. Do you agree with these revisions? If not, please explain in the comment area below.. 41

3. Do you have any other comment, not expressed in questions above, for the GVSDT?.................. 46

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Domion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered	RFC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

		Entities		
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	John Allen	City Utilities of Springfiel	SPP	1, 4
3.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
4.	Sean Simpson	Board of public utilities of kansas city	SPP	1, 3, 5
5.	Mark Wurm	BPUK	SPP	NA
6.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
7.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
8.	Brian Taggert	Westar Energy	SPP	1, 3, 5, 6
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	John Mayhan	Omaha Public Power District	MRO	1, 3, 5
11.	Ron McIvor	Omaha Public Power District	MRO	5, 1, 3
12.	Mahmood Safi	OPPD	MRO	1, 3, 5
13.	Anna Wang	Burns McDonald	SPP	NA

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
5.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	Dewayne Scott		SERC	1
5.	Tom Vandervort		SERC	5
6.	Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	Goerge Pitts		SERC	1
9.	Robert Bottoms		SERC	
10.	David Marler		SERC	1

				1	2	3	4	5	6	7	8	9	10
6.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
2.	Chuck Matthews	Transmission Planning	WECC	1
3.	Erika Doot	Generation Support	WECC	3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Steve Kern	FE Energy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	paul haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel	krupa	WECC	1
2.	dana	wheelock	WECC	3
3.	hao	li	WECC	4
4.	mike	haynes	WECC	5
5.	dennis	sismael	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Frank Gavvney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	E Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Jackson	MEAG Power	SERC	3
2.	Steve Grego	MEAG Power	SERC	5
3.	Danny Dees	MEAG Power	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Thomas McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	John Shaver	Southwest Transmission Cooperative	WECC	1
3.	Tom Alban	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	James Manning	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Charles Long	SERC Planning Standards Subcommittee	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NCEMC	SERC	1
3.	Jim Kelley	PowerSouth Energy Coop	SERC	1
4.	Philip Kleckley	SC Electric & Gas Co	SERC	1
5.	Bob Jones	Southern Company Service	SERC	1
6.	Pat Huntley	SERC Reliability Corp	SERC	10
7.	David Greene	SERC Reliability Corp	SERC	10
8.	Amir Najafzadeh	SERC Reliability Corp	SERC	10

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
18.	Individual	David Thorne	Pepco Holdings Inc and Affiliates	X		X							
19.	Individual	ryan millard	pacificorp	X		X		X	X				
20.	Individual	Brian Bejcek	Wolverine Power Supply Cooperative, Inc.	X									
21.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
22.	Individual	Jim Watson	Dynegy					X					
23.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
24.	Individual	Lynn Schmidt	NIPSCO	X		X		X	X				
25.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
26.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
27.	Individual	Winnie Holden	PSEG	X		X		X	X				
28.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)					X					
30.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
31.	Individual	Ken Gardner	Alberta Electric System Operator (AESO)		X								
32.	Individual	Thad Ness	American Electric Power	X		X		X	X				
33.	Individual	Michael Falvo	Independent Electricity System Operator		X								
34.	Individual	Wryan Feil	Northeast Utilities	X									
35.	Individual	Brian Evans-Mongeon	Utility Services								X		
36.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
37.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X	X	X	X				
38.	Individual	Scott Berry	Indiana Municipal Power Agency										
39.	Individual	Eric Bakie	Idaho Power Company	X		X							
40.	Individual	John Yale	Chelan PUD					X					
41.	Individual	Robert Casey	Georgia Transmission Corporation	X									
42.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
43.	Individual	Kirit Shah	Ameren	X		X		X	X				
44.	Individual	Don Jones	Texas Reliability Entity										X
45.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
46.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
47.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
48.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
MEAG Power	Southern Company Services, Inc. - Gen
Liberty Electric Power LLC	NAGF
Indiana Municipal Power Agency	Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum (NAGF)group for MOD-025.
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

1. **The GVSDT has revised attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: In general, the industry is supportive of the revisions made to Attachment 1 in Draft 3. In response to stakeholder comments several changes were made to provide consistent wording and clarity within Attachments 1 and 2. None of these changes is substantive.

Based on comments received the GVSDT determined that Note 3 of Attachment 1 added confusion and since it was not vital to Attachment 1 it was removed. Note 3 said "It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator. "

Clarifications were made in the standard regarding treatment of units in long term reserve shutdown, coordination with the Transmission Operator for staged testing, and collection of data for ambient condition corrections. The GVSDT also clarified that the first verification must be a staged test.

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	No	(1) We believe that Attachment 1 is clearer but we still have a few issues that the drafting team should address. In response to our previous comments, the drafting team indicated that a staged test is required prior to the use of operational data. In other words, the first verification must be through a staged test. The response to comments cited a sentence in sub-section 2 of the "Verification specifications for applicable Facilities:" in Attachment one as the reason. Essentially, it says if the previous test was unduly restricted, then the next verification should be a staged test. We do not think this is straight forward. What if there was no test? Could a test that did not occur be called unduly restricted? It would be much clearer for the drafting team to state directly either in Attachment 1, the requirements, the implementation plan or the effective date section that the first test must be a staged test.

Organization	Yes or No	Question 1 Comment
		Response: The SDT agrees and has added clarification to Attachment 1 under item 1 of "Periodicity for conducting a new verification". It now reads: "The first verification for each applicable Facility under this standard must be a staged test." (2) In subsection 3.4 of the "Verification specifications for applicable Facilities:" section of Attachment 1, we disagree with including "Other data as applicable." It is ambiguous, open ended and will only lead to inconsistent enforcement. Who decides what is applicable? The TP? The GO? The auditor? What happens if an auditor decides they believe a piece of data should be included but the TP and GO agree it shouldn't? If the other needed data cannot be enumerated, an open ended statement such as the one discussed here should not be added as a "catch all." This type of statement is unduly burdensome. **Response: We have changed the wording to provide clarification as follows: "Other data as determined to be applicable by the GO to perform corrections for ambient conditions."**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Texas Reliability Entity	No	1) Attachment 1, 2.2.2: We recommend changing the reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. **Response: Your comment suggests relaxing the standard with no supporting reason. The GVSDT believes that we have reached industry consensus with respect to this aspect of the standard and will not make further revisions** 2) Attachment 1, 2. We disagree with the statement that "...previously staged test that demonstrated at least 50 percent of the Reactive

Organization	Yes or No	Question 1 Comment
		capability shown on the associated thermal capability curve (D-curve). Unless there is a documented system limitation, an accurate test should result in 90% or better of the D-curve, after correction for ambient conditions. **Response: The GVSDT agrees with your comment however the 50% of the D-Curve requirement recognizes that the previously staged test provided the documented limitation that you reference.** 3) Attachment 1, 2.2 does not require wind and photovoltaic "applicable facilities" to verify Reactive Power capability at a minimum Real Power output. The ISO may still have reactive requirement for renewable resources at minimum output levels. If so, the resource should be required to demonstrate and test against those requirements? **Response: The ISO can request additional testing at any time. Defining minimum Real Power from variable generation resources can be problematic. For that reason the GVSDT allows testing variable generation plants at whatever load is available at the time of the test.** 4) Attachment 1, 2.1.1: What is the basis for "one hour?" Attachment 1, 3.1 says to record the value at the end of the verification period. What is the expected value(s) to be provided for the hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and wind turbines may not allow for a full hour. Current ERCOT regional criteria for the Reactive Power leading and lagging test duration is 15-minutes. **Response: The industry has reached a consensus that 1 hour is long enough for a unit to stabilize thermally. The GVSDT recognizes that a variable generation plant may not have constant output for one hour. The instantaneous values at the end of the one hour test are the values expected to be reported.**

Organization	Yes or No	Question 1 Comment
		5) Attachment 1, 3.2: If there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. **Response: The voltage schedule recorded should be the one that is in effect at the time of the test. Additional documentation on the voltage schedule should not be required since the TOP issues that voltage schedule.** 6) As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. **Response: Seasonal adjustments are expected to be calculated with the data that is recorded in Attachment 1, 3.4 if requested by the TP.** 7) Attachment 1, section 3: Generator Owner should also include the D-curve with the verification data. For many air-cooled units, the real and reactive capability can vary significantly with ambient temperature. The Transmission Planner needs both the ambient temperature and the D-curve data to verify the validity of the test. **Response: The verifications in MOD-025-2 are intended to demonstrate the capability of the unit that is reported or show limitations to that capability, not necessarily to demonstrate the D-curve.** 8) Attachment 1, 3.4: we suggest re-wording to "... perform corrections to Real Power ***and Reactive Power*** for different ambient conditions..." **Response: Corrections for ambient conditions are intended for Real Power as it can vary substantially for some units.**

Organization	Yes or No	Question 1 Comment
Response: The GVSDT thanks you for your comments. Please see responses above.		
Tennessee Valley Authority	No	1. Att 1, Periodicity for conducting a new verification: 1. For staged verification; recommend changing the allotted time to make a change to 12 months. From Att 1: "... of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months" - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. **Response: The GVSDT added the additional six month to perform another verification in order to allow the GO time to do this in a scheduled manner. The GVSDT believes that industry consensus has been achieved with regard to this issue.** 2. Att 1, Periodicity for conducting a new verification: 2. For verification using operational data; recommend changing the allotted time to make a change to 12 months. Att 1: "... discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months" - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. **Response: The GVSDT added the additional six month to perform another verification in order to allow the GO time to do this in a scheduled manner. The GVSDT believes that industry consensus has been achieved with regard to this issue.**

Organization	Yes or No	Question 1 Comment
		3. Att 1, Periodicity for conducting a new verification:, 1 For Staged verification; and 2. For verification using operational data; both steps require verification at least every five years. Recommend verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, "6 calendar years." Justification is to coordinate protective system relay testing during plant outages with the real and reactive power testing that can be performed during outage shut-down or start-up. **Response: The GVSDT believes that industry consensus has been achieved with regard to a five years testing cycle.** 4. Attachment 1, 3.6, add "voltage ration and," as follows: The existing GSU and/or system interconnection transformer(s) voltage ration and tap setting. Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies "transformer(s) tap setting"; Attachment 2, had data entries for "Voltage Ratio." Both values are legitimate transformer parameters. **Response: The GVSDT agrees and has corrected the oversight adding "voltage ratio" to Attachment 1, 3.6.** 5. Recommend Att 1, 4., be titled as "Record the following auxiliary load information:" Justification is that the current "step 4" is more of a substep to this new "step 4" description. **Response: The GVSDT disagrees and considers Attachment 1, Item 4 to direct the development of a simplified key one-line diagram as stated.** 6. Recommend Att 1, 4., current step text be moved to a substep 4.1, "Develop a simplified key one-line diagram ... " Justification is that this step is similar to the current "steps 4.1 and 4.2" **Response: The GVSDT has renumbered Attachment 1, 4.2 as 5 to**

Organization	Yes or No	Question 1 Comment
		provide clarity. 7. Recommend renumbering steps “4.1 to 4.2” and “4.2 to 4.3.” Justification is to change the current “step 4 to 4.1.” See items 4 and 5, above. **Response: See responses to comments 4 and 5 above.** 8. Recommend changing the current “step 4.2 / recommended step 4.3” to read as follows:”If an adjustment is requested by the TP, then develop the relationship between test conditions and generator output so that the amount of Real Power that can be expected to be delivered can be determined from a generator at different conditions, such as peak summer conditions [remove can be determined]... “ Justification is to reword for clarity. **Response: The GVSDT has revised this sentence for clarity as: “If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Exelon Corporation and its affiliates	No	1) Attachment 1 (general comment):Exelon appreciates the addition by the GVSDT of the exclusion that nuclear units are not required to perform Reactive Power verification at minimum Real Power output (Attachment 1 Section 2.2.3); however, as stated in the previous comments, Exelon still is concerned that nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with nuclear

Organization	Yes or No	Question 1 Comment
		plant specific NRC operating license. In response to Exelon's comments in the 9-27-12 Consideration of Comments, the GVSDT states that they "disagree with not requiring a verification to define the unit's reactive capability" and further states that they are "aware of nuclear units that have been safely tested to their leading power factor limits." Although the GVSDT may purport that it is safe to perform such testing there is not one unique design for a nuclear generating unit in the NERC Regional Entities. Exelon continues to believe that there should be a provision in the Standard to allow for such an exemption based on considerations for nuclear unit regulatory, unit stability or other potential equipment restrictions. To address the concern that the GVSDT has related to providing a blanket exemption for nuclear units, Exelon suggests that such an exemption must be justified, documented in writing, and accepted by the Transmission Planner. Exelon suggests that a new note be added to Attachment 1 as follows:"If a unit is restricted due to other regulatory, unit stability, plant operating procedures, or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate. A generating unit with such a restriction must be justified, documented in writing and accepted by the Transmission Planner." **Response: The GVSDT reaffirms, as stated in the previous response to comments, that challenging the plant's safety systems is not required by this standard.** 2) Periodicity for conducting a new verification: Attachment 1 Section related to the periodicity for conducting a new verification (page 15 of 22) second paragraph states: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." Experience shows that maintaining the

Organization	Yes or No	Question 1 Comment
		plant's substation bus voltage within the scheduled voltage range at some arbitrary value is often inadequate to allow maximum VAR output during staged Reactive Capability testing. In such cases the system operator would need to adjust the substation voltage, potentially close to a schedule limit. Exelon suggests that the sentence be revised as follows: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to coordinate with the Generator Operator to adjust the plants substation bus voltage as required to accommodate the desired reactive output." **Response: The GVSDT believes the standard, as worded allows for adjustments by the TOP but only to the limits acceptable to the TOP.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Associated Electric Cooperative, Inc. - JRO00088	No	Attachment 1, Parts 2.2.1 and 2.2.2, AECI does appreciate adequate Attachment 1 allowances for voltage-schedule restrictive operating conditions, so that actual Maximum and Minimum reactive capabilities that simply cannot be attained, are not required, as acknowledged per Notes 1 & 2. However we do question the value to industry, beyond initial testing per this standard, of the 5-year retesting and believe this Requirement will eventually be removed unless redrafted per responsible entities' internal controls program expectations. We do however agree with the requirement to retest when unit conditions change sufficiently to warrant retesting.
Response: The GVSDT thanks you for your comments. Periodic verification is necessary for discovering the equipment limitations that impact the unit MW or MVAR capabilities. The GVSDT believes that industry consensus has been achieved regarding the 5 year verification cycle.		

Organization	Yes or No	Question 1 Comment
Seattle City Light	No	Attachment 1, Section 2.1 explicitly states to run each unit at maximum real power and lagging reactive power for a minimum of one hour. Due to constraints of the load, water flow, or other operational characteristics such as generators' thermal limits this is typically not possible.
Response: The GVSDT thanks you for your comments. The generator's thermal limits should not adversely restrict a unit's capability verification. If your reference to water flow indicates the units in question are hydro units then Attachment 1, Section 2.1.2 applies and the load required is only that which is available at the time of the test.		
Cowlitz PUD	No	Cowlitz supports the comments developed by the NAGF SRT: 1. The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability...." It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years. **Response: The GVSDT does not see a conflict because R1.2, R2.2 and R3.2 state that you have 90 calendar days from the date the data is selected for submission of the data to the Transmission Planner. The two year limit in Attachment 1 refers to how far back in time you can go when you select operational data.** 2. The semantics regarding applicability should be made more consistent. The criterion, "Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System," in para. 4.2.3 appears to state that a station with two 500 MW NERC-registered fossil units and a standby, non-NERC-registered10 MW diesel genset connecting to the 13.2 kV bus, for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory

Organization	Yes or No	Question 1 Comment
		position, however, by saying that "For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." This would be better stated as, that "For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." **Response: Your example of a 10 MW diesel genset connected to a 13.2 kV bus would not be applicable because it is not directly connected to the BES nor is it a registered unit. There is no conflict between the Applicability Section and what is on page 15 since page 15 is only Verification specifications for what is found in the Applicability Section.** 3. Applying on p.16 an "unduly restricted" classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error that is fatal to the approvability of MOD-025-2 in its present form. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. **Response: The generator D-Curve is recognized as the absolute maximum achievable reactive capability. The reference to 50% of the D-curve is an acceptability criterion for using operational data in lieu**

Organization	Yes or No	Question 1 Comment
		of a staged test. 4. Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in comment #3 above are not related to transmission system conditions. Our concerns are amplified by the statement, "Observe auxiliary bus voltage limits," in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT's intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus dropout? Doing so would constitute an inacceptable operational practice. **Response: The GVSDT disagrees and believes you may have misinterpreted the standard relative to reactive capability testing and the primary reason for not reaching the D-curve is likely due to system conditions. The GVSDT has repeatedly commented and clearly stated in the standard that safe unit limits should not be challenged to perform this testing. Safe limits should be determined by the GO and testing should be stopped short of those limits and the reasons for stopping the test reported.** 5. Note 2 should be deleted as well ("While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification....") since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, "The recorded Mvar values were adjusted to rated generator voltage, where applicable," on P.21 should also be deleted. **Response: The standard does not require engineering analysis and its use is completely at the option of the Generator Owner.**

Organization	Yes or No	Question 1 Comment
		The GVSDT agreed after the previous posting in the Consideration of comments to remove this point ("The recorded MVAR values were adjusted to rated generator voltage, where applicable.") from Attachment 2. We apologize that it did not get removed from the standard and have removed it 6. Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently an oxymoron, given the dictionary definitions of "normal" as meaning standard, usual, typical, etc. and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range. **Response: The GVSDT has made changes for clarity of this language several times. We believe that there is now consensus for this language and have no plans for further changes.** 7. The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing...," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR

Organization	Yes or No	Question 1 Comment
		test. **Response: The suggestion to perform the testing at the same time was meant for staged testing only if desired by the GO. It is not a requirement for either operational data or staged testing to do both the Reactive Power and Real Power test at the same time.** 8. It would be helpful to state any coordination of units within a plant that is required or preferred for VAR testing. Running for example a three-unit plant with all units exporting MVARs together, then all importing together, will produce more conservative reactive power capabilities (i.e. the aux bus limits will sooner be encountered) than is the case for testing units one at a time with the other two under normal operation. Pull-together/push-together is the more realistic approach, however, for simulating the response of the plant to a Disturbance of the BES. **Response: It is envisioned that coordination of units within a plant would be necessary to perform reactive capability testing as those other units would be part of the reactive resources needed for optimal testing. It is not within the scope of this standard to analyze each plant for the best test configuration. The GVSDT suggests discussing optimal testing configurations with your TP. Your comment that states in part "….for simulating the response of the plant to Disturbance of the BES." Indicates possible confusion over this standard and MOD-026.** 9. The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per comment #6 above. **Response: Attachment 1, 2.1 describes the maximum Real Power output for both Real Power and Reactive Power capability testing. Attachment 1, 2.2.2 only provides the time needed before recording the data for the leading reactive power test at maximum real power.**

Organization	Yes or No	Question 1 Comment
		The GVSDT does not feel Attachment 1, 2.1 needs to be restated in Attachment 1, 2.2.2. 10. The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," are incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to. **Response: The hint is found in Attachment 1, 4.2 which states: "If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** 11. Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended. **Response: The format used should provide information comparable to that provided in Attachment 2 as stated in Requirements R1, R2 and R3. The GVSDT feels the directions are clear as currently drafted.** 12. GSU losses should have a separate line in Att. 2, since they are not specifically a tertiary load (item C in the Att. 2 diagram).

Organization	Yes or No	Question 1 Comment
		Response: The GVSDT believes that adequate data is recorded in Attachment 2 to determine gross and net Real or Reactive Power Capability as stated in the Purpose of the standard. 13. MOD-025 should not require "staged testing" without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the testing. **Response: TOP-002-2.1b covers real-time and near-real-time studies. It is believed that the TOP-002-2.1b, Requirement R13 is intended for verification of units that do not appear to be meeting the stated capabilities of the unit. MOD-025-2 is Real Power and Reactive Power verification for BES units for long range planning. Reasons for staged or operational testing requirements have been well documented in previous consideration of comments documents.** 14. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit

Organization	Yes or No	Question 1 Comment
		real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability. **Response: The GVSDT disagrees that "Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation." The GVSDT believes that the recent ballot results and comments show that industry consensus has been achieved. The GVSDT also disagrees that periodic testing within normal capability ranges would be detrimental to the BES reliability.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Duke Energy	No	Delete Note 3 on page 18 of the clean version, and delete the reference to Note 3 located on page 15 under "Verification specifications for applicable Facilities: #2". If a unit is equipped with AVR, the test must be conducted with the AVR in service.
Response: The GVSDT thanks you for your comments. The GVSDT agrees with this clarification and has revised the standard accordingly.		
Manitoba Hydro	No	General Comments - There is reference to certain actions that would be 'desirable' although not strictly required by the standard. This type of language can be problematic if the entity is held to this, or asked to explain why they did not meet the 'desirable' level.

Organization	Yes or No	Question 1 Comment
		Response: The GVSDT only found one use of the word "desirable" in the standard and it is in Note 2 of Attachment 1. The GVSDT believes that this language is appropriate and that stakeholder consensus has been achieved on this note. There appear to be requirements embedded in the attachment, and there should be no requirements here. For example, the word "shall" should be removed (since it implies a requirement) from (i) page 15 (clean version) "If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled . . . . ." and (ii) page 16 " . . . then the next verification shall be by another staged test, not operational data:" **Response: The language in these instances was revised to remove the use of "shall".** Another example which sounds like a requirement is on page 17 "Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." **Response: The language provides instruction regarding the adjustments requested by the Transmission Planner. The GVSDT believes that consensus has been achieved for this language.** Additionally, in 4.2 (i) "TP" should be expanded to Transmission Planner and (ii) the first sentence is worded poorly and should be clarified. **Response: This was corrected as noted.** Section 2.1 - Manitoba Hydro recommends removing the words "over excited" and replacing the words "normal (not emergency)" with "nominal". **Response: The language used here has been revised several times per**

Organization	Yes or No	Question 1 Comment
		stakeholder comments. The GVSDT believes that the consensus of stakeholders is to use these terms. Section 3.7 - "(real or reactive)" should be changed to "(real and reactive)". **Response: The GVSDT disagrees because the verification may not be for both Real and Reactive Power. The standard allows for independent verifications.** Page 15 (clean version) - The word "Load" should not be capitalized. **Response: The GVSDT agrees and has made the correction.** Page 17 (clean version), Note 1 - Manitoba Hydro suggests replacing 'improper tap settings' in Note 1 which reads "...such as rotor thermal instability, improper tap settings,..." with "improper voltage ratios". **Response: The GVSDT revised item 3.6 to add "voltage ratio" based on another stakeholder comment. We have revised Note 1 to add "voltage ratio" as well.** Page 18 (clean version), Note 5 - Manitoba Hydro suggests removing Note 5 which reads "Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output." Such descriptive wording is not required in a standard and should be left for reference books. **Response: The intent of Note 4 (formerly Note 5) is simply to clarify the testing required for synchronous condensers.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
pacificorp	No	PacifiCorp does not support the minimum one hour hold requirement for verifying a generating unit's maximum real power and lagging reactive power in Section 2.1.1 of Attachment 1. The one hour hold is excessive and fails to correlate to how a machine responds to a system event that

Organization	Yes or No	Question 1 Comment
		only lasts for a few minutes. The one hour requirement also puts unnecessary stress on plant equipment and directly contradicts the WECC Synchronous Machine Reactive Limits Verification Guideline that recommends holding a unit for a minimum of 15 minutes. PacifiCorp has followed this guideline since it was approved in 1996, and recommends this same standard to be applied in Attachment 1.
Response: The GVSDT thanks you for your comments. The industry has reached a consensus that 1 hour is long enough for a unit to stabilize thermally. The verifications performed under this standard do not relate to system events (as opposed to MOD-026-1 and MOD-027-1) and are intended to provide "accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability" as per the purpose statement. The GVSDT does not believe that there is a conflict with WECC guidelines as they are for a "minimum of 15 minutes".		
Dynegy	No	Recommend deleting the requirement in Attachment 1 section 2.2.1 to verify reactive power at minimum load. This puts the unit in an unstable condition and then stresses it by varying reactive power leading to the increased likelihood of a unit trip.
Response: The GVSDT thanks you for your comments. No test should be run that makes the unit unstable. The GVSDT suggests that minimum load be verified prior to performing any testing to avoid unit instability. The SDT is responding to FERC directives as part of the revisions of this standard. In one of the FERC directives (Order 693, Paragraph 1321) testing at multiple points was required. The standard does not require any testing that would violate any equipment operating limits or lead to equipment damage.		
PPL Corporation NERC Registered Affiliates	No	1)The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability...." It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years. **Response: The GVSDT does not see a conflict because R1.2, R2.2 and R3.2 state that you have 90 calendar days from the date the data is**

Organization	Yes or No	Question 1 Comment
		selected for submission of the data to the Transmission Planner. The two year limit in Attachment 1 refers to how far back in time you can go when you select operational data. 2)The phrasing regarding applicability should be made more consistent. The criterion, "Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System," in para. 4.2.3 appears to state that a station with two 500 MW fossil units (meeting NERC registry criteria) and a standby, 10 MW diesel genset connecting to the 13.2 kV bus (not meeting the NERC registry criteria), for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory position, however, by saying that "For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." This would be better stated as, that "For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." **Response: Your example of a 10 MW diesel genset connected to a 13.2 kV bus would not be applicable because it is not directly connected to the BES nor is it a registered unit. There is no conflict between the Applicability Section and what is on page 15 since page 15 is only Verification specifications for what is found in the Applicability Section.** 3) Applying on p.16 an "unduly restricted" classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended

Organization	Yes or No	Question 1 Comment
		range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. **Response: The generator D-Curve is recognized as the absolute maximum achievable reactive capability. The reference to 50% of the D-curve is an acceptability criterion for using operational data in lieu of a staged test.** 4) Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in our comments above are not related to transmission system conditions. Our concerns are amplified by the statement, "Observe auxiliary bus voltage limits," in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT's intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus drop-out? Doing so would constitute an unacceptable operational practice. **Response: The GVSDT disagrees and believes you may have misinterpreted the standard relative to reactive capability testing and the primary reason for not reaching the D-curve is likely due to system conditions. The GVSDT has repeatedly commented clearly stated in the standard that safe unit limits should not be challenged to perform this testing. Safe limits should be determined by the GO and testing should be stopped short of those limits and the reasons for stopping the test reported.**

Organization	Yes or No	Question 1 Comment
		5)Note 2 should be deleted as well ("While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification....") since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, "The recorded Mvar values were adjusted to rated generator voltage, where applicable," on P.21 should also be deleted. **Response: The GVSDT agreed after the previous posting in the Consideration of comments to remove this point ("The recorded MVAR values were adjusted to rated generator voltage, where applicable.") from Attachment 2. We apologize that it did not get removed from the standard and have removed it.** 6) Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720 MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently incorrect, given the dictionary definitions of "normal" as meaning standard, usual, typical etc and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range.

Organization	Yes or No	Question 1 Comment
		Response: The GVSDT has made changes for clarity of this language several times. We believe that there is now consensus for this language and have no plans for further changes. 7) The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing...," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR test. **Response: The suggestion to perform the testing at the same time was meant for staged testing only if desired by the GO. It is not a requirement for either operational data or staged testing.** 8) The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per our comments above. **Response: Attachment 1, 2.1 describes the maximum Real Power output for both Real Power and Reactive Power capability testing. Attachment 1, 2.2.2 only provides the time needed before recording the data for the leading reactive power test at maximum real power. The GVSDT does not feel Attachment 1, 2.1 needs to be restated in Attachment 1, 2.2.2.** 9) The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," is incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to.

Organization	Yes or No	Question 1 Comment
		Response: The hint is found in Attachment 1, 4.2 which states: "If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." 10) Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended. **Response: The format used should provide information comparable to that provided in Attachment 2 as stated in Requirements R1, R2 and R3. The GVSDT feels the directions are clear as currently drafted.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Ameren	No	While it is a step in the right direction to direct the Transmission Operator to take measures to maintain the system bus voltage of the plant under test at an acceptable level during the reactive power capability testing of the plant, this still does not mean that the plant would necessarily be able to reach its full reactive power output capability during the test. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then we believe that there needs to be some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed.

Organization	Yes or No	Question 1 Comment
Response: The GVSDT thanks you for your comments. Please reference Attachment 2, Note 1 for the permission you are requesting with regard to extrapolation.		
ExxonMobil Research and Engineering	No	No comments on this question.
Southern Company	No	
Idaho Power Company	Yes	Idaho Power System Planning as a Transmission Owner that owns synchronous condensers agrees with the revisions made to Attachment 1.
Response: The GVSDT thanks you for your comments.		
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	In our view, Ingleside Cogeneration LP believes the technical language used in the latest version of MOD-025-2 Attachment 1 has been refined to an acceptable point.
Response: The GVSDT thanks you for your comments.		
SERC Planning Standards Subcommittee	Yes	Paragraph 4.2 contains several typos and the intent is not clear. Recommend revise 4.2 to read: "An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."
South Carolina Electric and Gas	Yes	Paragraph 4.2 contains several typos and the intent is not clear. Recommend revising 4.2 to read: "An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so

Organization	Yes or No	Question 1 Comment
		requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.”
Response: The GVSDT thanks you for your comments. Based on your and other’s comments, the GVSDT revised this paragraph to: **“If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.”**		
Domion	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Luminant	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 1 Comment
American Transmission Company	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Chelan PUD	Yes	
Georgia Transmission Corporation	Yes	

2. **The GVSDT has revised the VSLs based on stakeholder comments. Do you agree with these revisions? If not, please explain in the comment area below.**

Summary Consideration: The industry is generally supportive of the VSLs. As a result of stakeholder comments, edits were made to VSLs for Requirements R2 and R3 to provide wording consistent with the VSL for Requirement R1– this is non-substantive because the level was not changed.

Organization	Yes or No	Question 2 Comment
Exelon Corporation and its affiliates	No	Although Exelon agrees with a majority of the revisions, it does not seem reasonable to assign a Severe VSL for a potential administrative oversight for not submitting the data to the Transmission Planner within a set period of calendar days equally to a complete failure to perform the required testing for an applicable generating unit. Exelon suggests that the administrative requirement for submitting data within a set period be limited to maximum of a High VSL and the application of the specific submission time periods be adjusted for the Low and Medium VSLs and the Severe VSL be revised to reflect inability to produce sufficient data to substantiate that the required testing was performed (i.e., the Generator Owner may have performed the test but is unable to produce any data to support the testing). As an example, the proposed example revision to the Severe VSL is as follows: The Generator Owner failed to produce data upon request of the Transmission Planner. OR The Generator Owner failed to verify the [applicable test] per Attachment 1 of an applicable generating unit.
Response: The GVSDT thanks you for your comments. The NERC VSL Development Guidelines call for providing multiple VSLs when there are varying elements in the requirement such as completeness of data and timely submission of data as well as failure to perform a verification. The GVSDT followed these guidelines in developing the VSLs for MOD-025-2.		

Organization	Yes or No	Question 2 Comment
Luminant	No	Luminant disagrees with the expanded VSLs and recommends that the SDT return to the VSL list in the previous posting. Luminant believes that the original VSL list is comprehensive and does not require expanding to include completeness of the data reported, or specific compliance to items, 1, 2, and 3 of the "Periodicity for conducting a new verification."
Response: The GVSDT thanks you for your comments. The VSLs were not revised appreciably from the previous posting. The NERC VSL Development Guidelines call for providing multiple VSLs when there are varying elements in the requirement such as completeness of data and timely submission of data as well as failure to perform a verification. The GVSDT followed these guidelines in developing the VSLs for MOD-025-2.		
Seattle City Light	No	The VSL associated with Attachment 1 Section 2.1 will often be violated, because due to constraints of load, water flow, or other operational characteristics such as generators' thermal limits it is typically not possible to run each unit at maximum real power and lagging reactive power for a minimum of one hour as required.
Response: The GVSDT thanks you for your comments. The GVSDT assumes that you are referring to variable generation in your comment. Attachment 1, Section 2.1.2 states: "Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification." If this is met, then there is no violation of the requirement and the VSLs are moot.		
Ameren	No	There seems to some discrepancy in the reporting date that the VSLs are based on when using the operational data to verify. The first section in the VSL for R1 is worded slightly differently than the same portion of the VSL for R2 and R3. For R1, the reporting date seems to be based on the date that the data is selected for verification based on historical data, whereas for R2 and R3 the reporting date seems to be based on the date when the historical operating point was reached. Please clarify the SDT's intention to have such a difference, as it could make a big difference in meeting the reporting date deadline, and cause confusion among Generator Owners.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comments. The GVSDT intended the language to be the same for each requirement. The VSLs for R2 and R3 were revised to match the language in R1.		
ExxonMobil Research and Engineering	No	No comments on this question.
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revised VSLs.
Manitoba Hydro	Yes	None.
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Duke Energy	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 2 Comment
pacificorp	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Wisconsin Electric Power Company	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 2 Comment
Chelan PUD	Yes	
Georgia Transmission Corporation	Yes	

3. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

Summary Consideration: The following note was added to the Effective Date section for clarity – "The verification percentage above is based on the number of applicable units owned."

As a result of stakeholder comment, clarification was added to the Effective Date section regarding regulatory approval in Canada.

In response to stakeholder comments, the following non-substantive changes were made in Attachment 2:

1) A clarifying phrase was added to the header in the "last verification" column

2) A bullet point in the Summary of Verification that was intended to be removed during the last comment cycle and was not, has now been removed

3) The tap setting and voltage ratio wording were made consistent throughout Attachments 1 and 2.

Organization	Question 3 Comment
ACES Power Marketing Standards Collaborators	(1) What measure does the effective date use when determining percentage of applicable Facilities that must be completed by the given date? Is it a percentage based on the net nameplate rating of the generator? We suggest this should be stated directly to avoid conflicts between what the auditor assumes versus what the registered entity assumes. **Response: The SDT has added a clarifying note as follows: "Note: The verification percentage above is based on the number of applicable units owned."** (2) Attachment 2 discusses subtracting tertiary real and reactive power to get net real and reactive power, yet there is no entry for it. Should there be an entry added in the form? **Response: Tertiary loads are accounted for on the one-line diagram and associated table as point C.** (3) The response to our last comments regarding inclusion of the last verification column indicated that a note would be added to indicate that this column would be blank for the initial verification. We could not find the note. Please add it. We were concerned a similar issue to the one

Organization	Question 3 Comment
	experienced with the Protection System Maintenance and Testing standard would be experienced. In the PRC standard, auditors interpreted statements in the standard to require data prior to the enforceable date even though registered entities were not required to keep it. It resulted in a number of violations. **Response: The GVSDT has added this note as follows: "Previous Data; will be blank for the initial verification"** (4) In applicability sections 4.2.1 through 4.2.3, please change "directly connected to the BES" to "that are part of the BES". Per the BES definition, generation units can be and are part of the BES. Using "directly connected to the BES" could draw in a non-BES unit. **Response: The GVSDT has used the registry criteria to identify applicable Facilities. The MVA limits shown will prevent non-BES units from being included under the standard.** (5) How will mothballed units be handled? If a mothballed unit is returned to service, is it treated like a new unit with the return date serving as the commissioning date? **Response: The GVSDT has added the following clarification to Attachment 1, Item 3 under Periodicity for conducting a new verification, "Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 12 calendar months. "**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Ameren	(1)We believe that for sets of generators that are designed and operated identically, there should be a provision allowing use of "Sister Units" for compliance as done in MOD-026. **Response: The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.** (2)We believe the 5 year cycle with a 66 month limit is too stringent. We request that due to possible outage scheduling issues or other impacts, extending this 66 month limit by 18 months allowing a maximum of 84 months between test verifications.

Organization	Question 3 Comment
	Response: The GVSDT believes that industry consensus has been achieved in this regard. Outages are not required for this testing. (3)Was it the intent of the SDT to leave out a minimum verification time of one hour for both MW and MVAR verification? Could the SDT please clarify their intention and if a minimum of one hour was intended? **Response: Attachment 1, Item 2.1.1 states: "Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour."**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Duke Energy	1) Attachment 2, Summary of Verification - Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) In the Consideration of Comments Report the Standard Drafting Team agreed to make this change, but it was overlooked. **Response: The GVSDT has made this correction.** 2) The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test - the requirements do not directly fulfill the purpose. **Response: The verifications performed under this standard are intended to provide actual performance data as inputs to the models and the GVSDT believes that industry consensus has been achieved in this regard.** 3) Leading VAR Staged Testing - Leading VAR staged testing provides little benefit to the BES and should only be performed once in an initial staged test or validation. The fact that the regions will not be able to provide operational data for the leading VAR test points requested, proves that the system usually doesn't require leading VARS. In the situations such as system recovery and lightly loaded BES where leading VARS may be required, the initial testing and validation that the unit's heat removal capability (such as lagging VAR operational data) is sufficient, should serve as satisfactory verification of the unit's capability. The risk (and cost) of repeated operation of the unit in the maximum leading VAR is not warranted for the little benefit it provides to the BES. The risk of

Organization	Question 3 Comment
	Step Iron degradation and loss of synchronous operation every five years far outweighs the benefit such testing would provide the BES once the unit has been proven capable. The lagging VAR capability test or validation will prove that the unit's heat removal capability has not been compromised. MOD-025-2 should be reworded to only require periodic validation (either by staged testing or operational data) for lagging VARS, and that periodic leading VAR testing only be required if the unit is not capable of passing the lagging VAR capability test or validation. **Response: The SDT is responding to FERC directives as part of the revisions of this standard. In one of the FERC directives (Order 693, Paragraph 1321) testing at multiple points was required. The standard does not require any testing that would violate any equipment operating limits or lead to equipment damage.** 4) Applicable Facilities - Verification of units between 20 MVA and 100 MVA provide little benefit to the BES for the risk and cost of performing the staged test for these units. The maximum VAR contribution for these units is in the 5 to 20 MVAR range, and the risk and cost for testing, documentation and auditing of units of this size is not warranted for the small benefit gained. If there is a specific need for a particular small unit to provide VAR support due to regional constraints, then it should be validated. But to require validation for all the small units that have little impact on the reliability of the BES, the cost is not warranted. The unit size applicability for PRC-019-1 and MOD-025-2 should be set equivalent to that specified by MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Texas Reliability Entity	1) Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning and Operations models for specific periods. **Response: Seasonal conditions were considered for Real Power. The GVSDT has revised this**

Organization	Question 3 Comment
	sentence for clarity as: "If an adjustment is requested by the TP, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. 2) In section 4, the phrase "directly connected to the Bulk Electric System" may have the unintended consequences of excluding a generator unit connected to the BES through a 69/138 kV autotransformer (for example). Suggest removing 'directly' from these requirements. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.** 3) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.** 4) TRE recommends changing to "Planning Authority or Transmission Planner" in the requirement sections instead of "Transmission Planner". The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. **Response: The GVSDT has set the requirements for model verifications to be submitted to the Transmission Planner. Per the NERC Reliability Functional Model, the Transmission Planner provides this information to the Planning Coordinator. The GVSDT believes that stakeholder consensus has been achieved in this regard.** 5) The Functional Entities are listed as the Generator Owner and the Transmission Operator. However, the VAR standards have the Transmission Operator provide the Generator Operator a voltage or reactive schedule and require the Generator Operator to maintain that voltage or reactive schedule. Should the Generator Operator be included in this standard for verification and

Organization	Question 3 Comment
	data reporting? There are many cases where the Generator Owner is not the Generator Operator and confusion could result (or incorrect data/testing) if different criteria were provided. **Response: Per the NERC Reliability Functional Model, the Generator Owner is the responsible entity for "Establish generating facilities ratings, limits, and operating requirements." (see page 50, item 1 of the Functional Model).** 6) Overall the timing is too long. Waiting 12 calendar months for verification impacts reliability. Based on this requirement, the capability could be reduced by 50% but not tested for 12 calendar months (or longer). That could put significant strain on a local system that may not be tested for an extended period and yet be compliant with the standard. **Response: The standard is intended to verify long term planning models. The GVSDT believes that industry consensus has been achieved in regards to the 12 month verification specification.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Wisconsin Electric Power Company	1. In Attachment 1 Section 2.2.1, we take issue with the requirement to verify reactive power capability at the minimum real power output. We are not convinced this is necessary for BES reliability. The reactive capability at this point can be estimated by the GO with sufficient accuracy for the planning model. Verification of reactive output at minimum real power requires considerable effort and resource scheduling flexibility for data which can be readily estimated without adverse impact to the BES. Especially for large units, it may require a multiple day effort to verify reactive power at the minimum and maximum real power points, due to issues with auxiliary equipment. **Response: The standard only requires testing up to the point any limit is reached and as such extended testing times should not be required. FERC Order 693 (Paragraph 1321) requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.** 2. Attachment 2: On the One Line Diagram and the following data table, it is indicated that the net unit capability is to be provided at the GSU high-side (Point F). This should be revised to allow the GO to provide the net capability at the GSU low-voltage side instead. There may not be adequate

Organization	Question 3 Comment
	metering capability at the GSU high-side, whereas metering at the generator voltage level is commonly available. **Response: The standard allows calculation of the net capability if appropriate metering is not available. See Section 4.1 of attachment 1.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Chelan PUD	1. It is unclear how auxiliary load should be calculated where several units share a common station service power supply and all units are not in operation (multi unit hydro plant). Suggest some guidelines in allocation in these cases should be included. **Response: The auxiliary load should be allocated amongst the running units. The standard allows for engineering analysis and that could be utilized to calculate the appropriate auxiliary load.** 2. It may not be possible to generate maximum real power for one hour for hydro with small reservoir volumes. Similar to run of river hydro, reservoir volume or other license requirements may restrict this ability. Suggest a similar allowance in these cases to the run of river power qualification. **Response: Section 2.1.2 of Attachment 1 addresses verification of variable resources and only requires that verification be conducted at the maximum level that can be achieved at the time of the verification. Wind, solar, and run of river hydro were mentioned only as examples of variable resources.** 3. R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which

Organization	Question 3 Comment
	engineering analysis is required for model verification. **Response: The standard does not require engineering analysis and its use is completely at the option of the Generator Owner.** 4. It may not be possible to test full reactive capability at minimum power for hydro units due to the broad capability curve without exceeding TOP established voltage schedules. I suggest going to some percentage of the "full" value to verify the curve with concurrence of the TOP and TP in these cases or test documentation of limiter settings. If the GO is required to perform staged test, the TOP and RC must be able to support it. Some system should be established where this cannot be done. **Response: The standard only requires testing to the point a limit is reached. There is no requirement to reach any "full value".**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Tennessee Valley Authority	1. Entire Attachment 2, recommend linking Att 2 data entries to Att 1 requirements by adding (e.g. Att 1 requirement _____) in parenthesis, to each Att 2 line/bullet. Justification is to define the source requirement for the data. **Response: The standard does not require use of Attachment 2 as is. The Generator Owner can modify Attachment 2 or create an alternate form that provides the required data. Cross references to Attachment 1 could be included in the revised form if the Generator Owner wishes** 2. Attachment 2, Summary of Verification, recommend adding the following bullet under "Transformer Voltage Ratio: ..."Add: "Transformer Tap Setting: GSU ___, Unit Aux ___, Station Aux ___, Other Aux ___"Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies "transformer(s) tap setting"; Attachment 2, had data entries for "Voltage Ratio." Both values are legitimate transformer parameters. **Response: The SDT agrees with your suggestion and has made the suggested change to Attachment 2.** 3. Overall Standard, The focus of this standard appears to be on testing rather than on verifying the

Organization	Question 3 Comment
	limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test. Justification is that the requirements do not directly fulfill the purpose. **Response: The GVSDT believes that the requirements do fulfill the purpose and that industry consensus has been achieved in this regard.** 4. Overall Standard, recommend removing the requirements to perform “staged testing.” Justification is that staged testing should only be required if requested by the TOP. Justification is that verification of the true reactive limits via staged testing often produces less than optimal results because of transmission system constraints. **Response: Reasons for staged or operational testing requirements have been well documented in previous consideration of comments documents.** 5. Standard, 4.0 Applicability, The unit size applicability for MOD-025-2 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027 (i.e. MOD-026-1 Draft, 4.2, Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ...(including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ...(including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ...(including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.) **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Manitoba Hydro	1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? **Response: The reason for a phased implementation is to allow Generator Owners a reasonable schedule for testing.** 2. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled

Organization	Question 3 Comment
	"Consideration for early Compliance" with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1). **Response: The phased implementation was developed to allow GO's sufficient time to perform the verification on their units. Because of this, the GVSDT does not believe an early compliance provision is needed.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Alberta Electric System Operator (AESO)	1. In section 4.2 The AESO considers the existing applicability for reactive power verification to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger. **Response: The GVSDT has used the registry criteria to identify applicable Facilities and believes that industry consensus has been achieved in this regard.** 2. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect. **Response: The standard allows up to 12 months to complete a test upon discovering the change. If the issue is rectified before the end of the 12-month period a test is not required.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Independent Electricity System Operator	1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by: a. In the Implementation Plan, under the Section "In those jurisdictions where regulatory approval is required:", adding a phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities,"

Organization	Question 3 Comment
	right after "following applicable regulatory approval" and before "each Generator Owner..."b. In Section A5.1 of the standard, adding the same phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval," and before "each Generator Owner...". **Response: The GVSDT has made the suggested clarifying revision.** 2. There are four measurements of "Gross Reactive Power Capability" for generators: over-excited and under-excited at minimum and maximum active power outputs. Which one of the four measurements should be recorded in Appendix 2 under "Gross Reactive Power Capability"? **Response: By utilizing the check boxes in Attachment 2, the particular test or tests that are being recorded are specified.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
ExxonMobil Research and Engineering	A stated purpose of Generator Verification is "to ensure that generator models accurately reflect the generator's capabilities and operating characteristics." Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets' capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load's process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load's production schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same. Additionally, the SDT should define the term 'Synchronous condenser' so that it is

Organization	Question 3 Comment
	clear that a large synchronous motor is not a synchronous condenser.
Response: The GVSDT thanks you for your comments. The GVSDT has used the registry criteria to identify applicable Facilities . If a unit meets the registry criteria it is obligated to comply with the standard. **The GVSDT feels that the accepted industry understanding would not allow a synchronous motor to be confused with a synchronous condenser.**	
Florida Municipal Power Agency	A synchronous condenser can be owned by either a TO or GO. For instance, there are installation of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO whoever owns the synchronous condenser.
Response: The GVSDT thanks you for your comments. There are separate requirements for a GO and a TO. Requirement R2 applies to a GO who owns a synchronous condenser and Requirement R3 applies to a TO that owns a synchronous condenser. A GO will not need to register as a TO if they own a synchronous condenser.	
Lincoln Electric System	Although supportive of the standard drafting team's efforts, LES believes MOD-025 could be further enhanced in consideration of the following recommendations. Recommend Attachment 1 "Periodicity for conducting a new verification" be revised to require verification of the Real Power capability on an annual basis with Reactive Power remaining at every 5 years. In consideration that regions such as the MRO and SPP maintain existing procedures requiring members to perform Real Power verification at a minimum of annually, LES believes this reduced timeframe is not only reasonable but also achievable for entities. Additionally, it seems reasonable to expect a re-verification be performed if the Real Power is reduced by as little as 5 percent as several units with that level of lost capacity could be significant in adversely affecting the integrity of the BES. **Response: The SDT believes that industry consensus has been achieved regarding the required**

Organization	Question 3 Comment
	periodicity of testing. Recommend Attachment 1 “Verification specifications for applicable Facilities” Part 3.4 be modified to specify the duration of the verification period and that the data supplied should be an average of the verification test period. - Per the standard, the purpose of MOD-025 is to ensure accurate information is available for the planning models in order to assess BES reliability. NERC annually builds 4 seasonal peak models (summer, winter, spring and fall) in addition to a spring minimum model. Within these models the TPs must provide Real Power maximum and minimum values and up to 10 sets of correlated real and reactive values in order to model a generators “D curve”. As such, LES would recommend that the GO develop these values and provide them to the TO. While Real Power Max is tested it is only done under the conditions of a single season, it would then be up to the TP to adjust the MW output for the other 3 seasons. LES believes the GO is the more appropriate person to make these adjustments rather than the TP. Additionally, Real Power minimum testing is not addressed within this standard. LES believes with the increase in highly variable generation, such as wind, generators may end up operating at their minimums much more than they have done historically and therefore Real Power minimums should be verified on an annual or 5 year basis as well. In terms of Reactive Power generation, a GO should be required to go beyond what is required in the current Attachment 2 and align with the number of correlated Real/Reactive sets which the TP is required to provide in their models to NERC. - In further support of BES reliability, LES recommends that the net Real Power output for generating facilities be adjusted based on a high temperature for the month based on the model that the Real Power output is being developed for, i.e. summer, winter, spring, fall, or minimum model. The criteria for determining what should be used for a high temperature adjustment point could be an average of the entity’s high temperature for the month over a ten-year period or possibly the 0.4% ASHRAE temperature could be used. LES believes it would not be unreasonable to expect that data be supplied by the GO for the seasons required for model submission by the TP. **Response: If the Transmission Planner requires ambient adjustments to the tested values the standard requires that adjusted values be provided (Section 5 of Attachment 1). The standard requires real power testing at minimum load.**

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comments. Please see responses above.	
American Transmission Company	ATC recommends the following changes: Attachment 1, Periodicity for new verification Item 3 - Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or a mutually agreed verification date." **Response: The GVSDT believes that testing of new facilities should be conducted within one year and that stakeholder consensus has been achieved regarding this language.** Attachment 1, Verification Specifications Item 2.1.2 - The wording is unclear near the end of Item 2.1.2. ATC recommends this be changed to read, "Reschedule the test of the facility within six months after being unable to test at or above the 90 percent threshold". **Response: The GVSDT disagrees. The six month interval is the period allowed to complete the testing following the date that the facility has 90 percent or more of its units available to test.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Domion	Dominion suggests that footnote 1 not contain the capitalized term Wind Farm Verification as this is not defined in either this standard or the NERC Glossary of Terms.
Response: The GVSDT thanks you for your comments. The GVSDT agrees and has revised this to "Wind farm verification…"	
Idaho Power Company	Idaho Power System Planning as a Transmission Owner that owns synchronous condensers has the following comments for the GVSDT to consider: Attachment 1 - Item 2.1.1 lists the verification duration for a synchronous generating unit at maximum real power and maximum reactive power with a one hour testing duration. Idaho Power System Planning comments that the voltage schedule may be difficult to maintain during a one hour test at maximum reactive power for a one hour test during for N-0 system conditions. Idaho Power System Planning asks the GVSDT to consider a 30 minute testing duration for performing the verification to be consistent with the 30 minute duration established for operators to make manual

Organization	Question 3 Comment
	system adjustments following contingency events. **Response: The time period selected was based on allowing for time for the unit to achieve a stable operating condition. The standard does not require exceeding any limits including voltage schedules during the test.** Attachment 1 - Item 2.1.2: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for variable generating units. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for variable generating units for the maximum reactive capability test. **Response: The standard does not differentiate the type of unit being tested and the SDT does not see a need to do so. For reactive testing, the standard only requires recording the value achieved at the end of the test period.** Attachment 1: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for synchronous condensers. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for synchronous generators for the maximum reactive capability test. Requirements to submit verification with 90 days of test date are unreasonable. 365 days is more reasonable, and is consistent with MOD-026-1 and MOD-027-1. **Response: See response to question 2 above. The SDT believes the 90 day deadline is reasonable and industry consensus has been achieved on this issue.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Northeast Power Coordinating Council	If the primary purpose of obtaining net Real Power and net Reactive Power is to build system models to support planning studies, then the Drafting Team should consider that MOD-025 may not be required and could be eliminated. Under Standard IRO-010-1a the Reliability Coordinator can require GOs and TOs to submit Real and Reactive Power data in a format the RC deems necessary. The detailed requirements of MOD-025 can be addressed in IRO-010-1a. **Response: The verifications required under MOD-025-2 are to verify the unit capability for an applicable Facility, not real-time characteristics as required in IRO-010-1a. The drafting team is**

Organization	Question 3 Comment
	also addressing a FERC Order 693 directive to: *"direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range".* This was discussed during the first comment period of the standard and the majority of stakeholders agreed with our approach. Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. **Response: The SDT has added a clarifying note as follows: "Note: The verification percentage above is based on the number of applicable units owned."** If the Drafting Team believes that a separate Standard to verify the gross and net Real and Reactive Power of the turbine generator is required, then MOD-025 should be limited to requiring the reporting of maximum Real and Reactive Power only. In our view the detailed data requirements specified in Attachment 1 and 2 are not required for planning studies. The data in Attachments 1 and 2 have value to plant personal to evaluate unit efficiency and performance, but this data is not needed to support reliability. This data is more relevant to market functions. **Response: The verifications required under MOD-025-2 are to verify the unit capability for an applicable Facility. The drafting team is also addressing a FERC Order 693 directive to: *"direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range".* This was discussed during the first comment period of the standard and the majority of stakeholders agreed with our approach. The other data is provided to make adjustments if requested.**
Response: The GVSDT thanks you for your comments. Please see responses above.	

Organization	Question 3 Comment
South Carolina Electric and Gas	In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027.
SERC Planning Standards Subcommittee	In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The GVSDT thanks you for your comments. The GVSDT believes that the verification periodicity for Real Power and Reactive Power capability is appropriate at five year intervals and was addressed in previous comment periods. The GVSDT believes that stakeholder consensus has been achieved in this regard.	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Ingleside Cogeneration LP agrees that the ability for Transmission Planners and other operating entities to be able to rely on a generator's available real and reactive capacity under system duress is essential to BES reliability. In addition, the technical veracity and implementation time frames in the latest version of MOD-025-2 are far improved over previous versions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R1 and R2) must contain language that focuses on the strength of the validation process - not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed - even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation.

Organization	Question 3 Comment
	2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects
Response: The GVSDT thanks you for your comments. Your issues relate to the "Find, Fix and Track" process that was most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states:"Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that *identifies, assesses, and corrects deficiencies*, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months:" This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of MOD-025 are to simply verify the output of an applicable Facility and report it. Under this standard, the responsible entity either performed the verification and reported it or they didn't. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.	
JEA	JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Response: The GVSDT thanks you for your comments. The GVSDT did not receive any comments from the NAGF, however others have mirrored the intent to concur with their comments (see specifically Cowlitz). We have responded to those comments above. The CEAP is not in effect as this time and cannot be implemented at this time.	
Exelon Corporation and its affiliates	Section D, "Compliance," Part 1.2, "Evidence Retention," (page 6 of 22) first paragraph is unnecessary and redundant since the retention periods specified are for the time period since the last compliance audit. Exelon suggests that this paragraph be deleted in its entirety.

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comments. The first paragraph of this section is boilerplate language provide by NERC for inclusion in all standards.	
Southern Company	The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. An engineering study for reactive capability is an option that needs to be allowed by this standard Currently, the standard is more of a performance test than a model verification test - the requirements do not directly fulfill the purpose. Applying an “unduly restricted” classification to reactive power verification results that fall short of 50% of the thermal capability curve (page 16) creates a technical error that does not prove or disprove the reactive capability of the generating unit. The D-curve represents the thermal characteristic of a single component (generator). The reactive capability of a generation unit system is also a function of other factors. These other factors include the transmission system bus voltage, GSU impedance and tap setting, unit auxiliary transformer and downstream station service transformer impedances and tap settings, station service bus loadings and voltage limits, and the excitation limiter settings. Staged testing has limitations when attempting to prove a unit’s reactive capability. We currently use an engineering assessment approach that establishes a unit’s expected reactive capabilities using an analytical model. The model has been validated using historical operational data. The model takes into account all the above factors and is used to estimate the unit’s reactive capabilities for extreme system voltage conditions when unit’s reactive limits will be challenged. The limits are then reviewed by plant operations to ensure any operational limitations have been identified and factored into the assessment. This has proven to be a better process for establishing the reactive limits needed for the transmission planning system models than the use of staged test data. MOD-025 should not require “staged testing” without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the

Organization	Question 3 Comment
	testing. The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability. The recorded Mvar values were adjusted to rated generator voltage, where applicable," on p.21 should be deleted because it does not make sense to do this.
Response: The GVSDT thanks you for your comments. Historical operational data may be used for subsequent verifications if the data meets the requirements in the standard. The GVSDT has developed the applicability of the standard based on the NERC registry criteria. **Again, MOD-025-2 allows the use of historical operational data for re-verifications. Equipment problems that limit a units capability will not always manifest themselves during normal operations. Reactive limitations reported under the VAR and TOP standards are Real-time or Operations Planning issues and are not reported to the Transmission Planner. These issues have been addressed during prior comment periods. The GVSDT agreed after the previous posting in the Consideration of comments to remove this point ("The recorded MVAR values were adjusted to rated generator voltage, where applicable.") from Attachment 2. We apologize that it did not get removed from the standard and have removed it.**	
NIPSCO	This is the information that generator owners are supposed to provide every year to transmission owners as part of the MOD-10 data submittal. Why a new standard is being developed instead of

Organization	Question 3 Comment
	modification of the existing MOD-10 is questionable. The burden for complying with this standard falls almost entirely with the generation group, e.g., electric production. Given the above, Transmission Planning recommends a vote in favor of this standard.
Response: The GVSDT thanks you for your comments. MOD-011 relates to steady state data requirements and requires the following data be submitted with respect to generating units: **"R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status."** **MOD-025-2 requires that the capability of a unit be verified as, over time, equipment operating characteristics change.**	
Wolverine Power Supply Cooperative, Inc.	This standard is redundant. We are already required by MISO to provide real power data. It would be more logical for this standard to be applicable to the RTO because they are already asking for most of this data. I would rather have MISO expand what they are asking for and have them pass the data along to NERC, than to have to comply with two entities asking for the same thing with slightly different methods.
Response: The GVSDT thanks you for your comments. The standard applies continent-wide and does not require that any data be submitted to NERC. This standard contains requirements to provide data to Transmission Planners. Any procedures developed by an ROT or ISO are in addition to NERC standards. The same data may possibly satisfy both. It is up to the individual entities to determine whether or not this is the case.	
Utility Services	Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comments. The GVSDT has added a note to provide clarification: "Note: The	

Organization	Question 3 Comment
verification percentage above is based on the number of applicable units owned.	
PSEG	We voted “Negative” on this standard the reasons shown below: This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1.1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a “team” with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as “applicable facilities,” while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments:”The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.”The SDT responded as follows:”The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.”In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.”PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.” We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. **Response: The GVSDT is indeed working as a “team” with these standards. Each individual standard was developed based on the reliability needs and benefits that each specific standard**

Organization	Question 3 Comment
	requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor will the applicable facilities necessarily be the same. As you are the only commenter that has raised an issue regarding the applicability of synchronous condenser, the GVSDT concludes that stakeholder consensus has been achieved with respect to the inclusion of synchronous condensers in MOD-025-2. This SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1.2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1 R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all "modelers," the result will be outdated data in someone's model, which can have a bad result. The team should have one broad "data sharing" policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it. **Response: The GVSDT has written the requirements of this body of standards based on the NERC Reliability Functional Model. The requirements of Reliability Standards MOD-010-0. MOD-011-0, MOD-012-0 and MOD-013-1 address the requirement for steady state and dynamic models (which are planning models) and the dissemination of these models to appropriate entities. The data to build Real-time models that are necessary for reliability and used by Reliability Coordinators and Transmission Operators are addressed in standards IRO-010-1a and TOP-003-2 respectively. The GVSDT does not see any reason to include duplicative requirements in this standard.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
PPL Corporation NERC Registered Affiliates	Without some exemption, we disagree with the GVSDT linking generator applicability of this standard to the Compliance Registry Criteria. Instead, the approach to applicability should be the

<table>
<tr><th>Organization</th><th>Question 3 Comment</th></tr>
<tr><td></td><td>same as what is used/proposed in MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual units greater than 100 MVA directly connected to the BES, etc.) Other than that size unit, use regional criteria to address any smaller units identified as critical to the BES in a given region. Consistency of criteria among the standards within this Project 2007-09 should be the same.</td></tr>
<tr><td colspan="2">Response: The GVSDT thanks you for your comments. The GVSDT has developed the applicability of MOD-025-2 based on the registration criteria. Each individual standard in this project has been developed based on the reliability needs and benefits that each specific standard requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor will the applicable facilities necessarily be the same.</td></tr>
<tr><td>Xcel Energy</td><td>Xcel Energy questions the reliability value of determining the maximum leading reactive power value at maximum real power output. This is not an operating regime for most generating units, so operational data will not be available, and operating at maximum power would normally occur during higher system load conditions when the loss of a generating unit due to a mistake during a test would stress the system more severely.</td></tr>
<tr><td colspan="2">Response: The GVSDT thanks you for your comments. During the comment period of June 15 – July 15, 2011 of MOD-025-2, the SDT asked the following question:

“5. The draft standard requires that the Reactive Power capability be verified at four points: over-excited (lagging) and under-excited (leading) reactive capability at (1) the rated Real Power capability and (2) expected minimum Real Power output. The SDT believes that this is consistent with the FERC directive in Order 693 at P1321, “Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit’s operating range.” Do you agree that the four points proposed by the SDT is adequate to provide a straight line approximation to a unit’s Reactive Power capability over its actual operating range? If not, please explain.”

The majority of stakeholders agreed with the proposed points. A note was added to Attachment 1 to address comments regarding leading capability: “Note 4: The verification is intended to define the limits of the unit’s capabilities. If a unit has no leading capability, then it should be reported with no leading capability, or the minimum lagging capability at which it can operate.”

To minimize stress to the system, the following is included in Attachment 1 – “If the Reactive Power capability is verified through</td></tr>
</table>

Organization	Question 3 Comment
test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." **The GVSDT believes that stakeholder consensus has been reached on this issue.**	

END OF REPORT

Consideration of Comments

Project 2007-09 Generator Verification
MOD-027-1

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to MOD-027-1. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 46 sets of comments, including comments from approximately 152 different people from approximately 98 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration

The vast majority of commenters agreed with the revisions to Attachment 1 clarifying that for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner, and that units which respond to over-frequency would need to have verification performed. No modifications were made to the draft standard as a result of industry comments for Question 1.

The vast majority of industry agreed that the revised Attachment 1 is clearer. There were a few minority comments about some of the specific rows in the Attachment, including proposals to refine the proxy sister unit philosophy and to move capacity factor philosophy back to the Applicability Section. However, the vast majority of industry agreed with the modified Attachment 1 and no further revisions were made to Attachment 1.

Based on stakeholder comments, the GVSDT made the following clarifications to the standard:

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

- In the Effective Date section 5.3, the word “thirty” after the word “quarter” was inserted in the standard by mistake. As such, the SDT removed the word “thirty.” Also, in 5.1, the GV SDT changed the beginning of the first sentence from: “For Requirements R1, and R3 through R6 …“ to “For Requirements R1, and R3 through R5 …“ to reflect that there are five, not six requirements in the standard.

- The wording, “… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities,” in Section 5.1 was moved to right after “… approved by applicable regulatory authorities …” And that same wording was moved to right after, “… following applicable regulatory approval …” in Sections 5.2 to 5.4. Also, the same phrase was appended to each of the four bullets in the Effective Date Section, “… in those jurisdictions where regulatory approval is required …” of the Implementation Plan right after, “… following applicable regulatory approval.” This was done to address regulatory approvals in Canada.

- In the Applicability section 4.2.3, added the word “in” so that the phrase now reads, “Generation in the ERCOT Interconnection…” to be consistent with the language associated with the other interconnections (sections 4.2.1 and 4.2.2).

- Revised the first sentence in R1 to read: “Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request …”

- The SDT has refined the applicable portion of Part 2.1 to read, “Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both.” Stakeholders believed that this added clarity to the Requirement.

- In the previous posting, there was a problem with footnote 4 where the language, “Error! Bookmark not defined,” was included in the language of the Requirement R4. This has been corrected.

- Several commenters provided suggestions for improvements to Requirement R5. The GVSDT clarified that the response by the Transmission Planner to the Generator Owner concerning the results of testing the model useability is required to be a written response. Also, for ease of reading, the GVSDT moved the last sentence in the requirement to after the Requirement Parts 1-3.

Index to Questions, Comments, and Responses

1. The GVSDT has revised Attachment 1 to attempt to clarify that, for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Do you agree with this revision? If not, please explain in the comment area below. ... 12
2. The GVSDT has revised Attachment 1 to make the periodicity requirements more clear. Do you agree with these revisions? If not, please explain in the comment area below. 17
3. Do you have any other comment, not expressed in questions above, for the GVSDT?..................... 26

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Domion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	John Allen	City Utilities of Springfiel	SPP	1, 4
3.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
4.	Sean Simpson	Board of public utilities of kansas city	SPP	1, 3, 5
5.	Mark Wurm	BPUK	SPP	NA
6.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
7.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
8.	Brian Taggert	Westar Energy	SPP	1, 3, 5, 6
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	John Mayhan	Omaha Public Power District	MRO	1, 3, 5
11.	Ron McIvor	Omaha Public Power District	MRO	5, 1, 3
12.	Mahmood Safi	OPPD	MRO	1, 3, 5
13.	Anna Wang	Burns McDonald	SPP	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	Dewayne Scott		SERC	1
5.	Tom Vandervort		SERC	5
6.	Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	Goerge Pitts		SERC	1
9.	Robert Bottoms		SERC	
10.	David Marler		SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1
2.	Chuck Matthews	Transmission Planning	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
3.	Erika Doot	Generation Support	WECC	3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Steve Kern	FE Energy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Frank Gavvney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	E Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Jackson	MEAG Power	SERC	3
2.	Steve Grego	MEAG Power	SERC	5
3.	Danny Dees	MEAG Power	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	John Shaver	Southwest Transmission Cooperative	WECC	1
3.	Tom Alban	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	James Manning	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Charles Long	SERC Planning Standards Subcommittee	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NCEMC	SERC	1
3.	Jim Kelley	PowerSouth Energy Coop	SERC	1
4.	Philip Kleckley	SC Electric & Gas Co	SERC	1
5.	Bob Jones	Southern Company Service	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Pat Huntley	SERC Reliability Corp	SERC 10										
7.	David Greene	SERC Reliability Corp	SERC 10										
8.	Amir Najafzadeh	SERC Reliability Corp	SERC 10										
15.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
16.	Individual	David Thorne	Pepco Holdings Inc and Affiliates	X		X							
17.	Individual	ryan millard	pacificorp	X		X		X	X				
18.	Individual	Brian Bejcek	Wolverine Power Supply Cooperative, Inc.	X									
19.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
20.	Individual	Jim Watson	Dynegy					X					
21.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
22.	Individual	Lynn Schmidt	NIPSCO	X		X		X	X				
23.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
24.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
25.	Individual	Winnie Holden	PSEG	X		X		X	X				
26.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
27.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)					X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
29.	Individual	Ken Gardner	Alberta Electric System Operator (AESO)		X								
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Wryan Feil	Northeast Utilities	X									
33.	Individual	Brian Evans-Mongeon	Utility Services								X		
34.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
35.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X	X	X	X				
36.	Individual	Scott Berry	Indiana Municipal Power Agency										
37.	Individual	Eric Bakie	Idaho Power Company	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
38.	Individual	John Yale	Chelan PUD					X					
39.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Don Jones	Texas Reliability Entity										X
42.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
43.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
44.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
45.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
46.	Individual	John Martinsen	Snohomish County PUD No.1	X		X	X	X	X			X	

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
MEAG Power	Southern Company Services, Inc. - Gen
Snohomish County PUD No.1	Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Liberty Electric Power LLC	NAGF
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

1. **The GVSDT has revised Attachment 1 to attempt to clarify that, for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of commenters agreed with the revisions to Attachment 1 clarifying that for units that do not respond to frequency excursions, Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner, and that units which respond to over-frequency would need to have verification performed. No modifications were made to the draft standard as a result of industry comments for Question 1.

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	No	Attachment 1 Row 7 leaves the impression responding to frequency excursion is merely a choice and this impression is harmful to reliability. Few "applicable units" should be unresponsive to over and under frequency excursions. If Generator Owners can choose to not help regulate frequency by simply notifying the Transmission Planner, why would any Generator Owner continue to regulate frequency? The attachment should be changed so units are unresponsive to frequency excursions only under conditions accepted by the Transmission Planner.
Response: The GVSDT thanks you for your comment. The SAR for this draft standard calls for the verification of the generator's Turbine/Governor and Load Control or Active Power/Frequency Control Function model data. Performance or operational requirements are beyond the scope of this standard. It is important that the correct response be modeled so that the simulation represents reality. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Cowlitz PUD	No	Cowlitz supports the comments of the NAGF SRT:1. The SDT should consider moving the capacity factor exemption information found

Organization	Yes or No	Question 1 Comment
		inAttachment 1, row 8 into the applicability section. The applicability section should allow anentity to be able to determine if the standard applies to them and be able to determine thescope of the facilities affected. It is best for those impacted to immediately know which unitsare in the scope and not have to realize the scope from a detailed study of the table ofAttachment 1. This would allow row 8 of Attachment 1 to be deleted.
Response: The GVSDT thanks you for your comment. The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Oncor Electric Delivery Company	No	Oncor does not support the position that the Transmission Planner (TP) is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP.Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the Planning Authority (PA) only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Response: The GVSDT thanks you for your comment. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with both the functional model and the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.		

Organization	Yes or No	Question 1 Comment
Ameren	No	We believe that there is a discrepancy between the language in the requirement and VSL for R4 and Row 4 of the Attachment 1. In the requirement, a 180 day period is stated, while in Row 4 of Attachment 1, a 365 day period is stated.
Response: The GVSDT thanks you for your comment. R4 requires a Generator Owner to provide revised model data or plans to perform model verification within 180 days of changes to the equipment. If the Generator Owner chooses to plan to perform model verification, then when that verification plan is submitted to the Transmission Planner, then in accordance with Requirement 2, Row 6 of Attachment 1 would specify that the Generator Owner has an additional 365 days to actually perform the verification – including transmitting the verified model, documentation, and data to the Transmission Planner.		
PPL Corporation NERC Registered Affiliates	No	Why wouldn't the GVSDT just identify (i.e. show reference note on Attachment 1 table) that "Applicable units does not include units that don’t respond to frequency excursions (e.g., base-loaded units)"?
Response: The GVSDT thanks you for your comment. The SDT decided to place all the scenarios that effectively “exempt” otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
ExxonMobil Research and Engineering	No	No comments on the question.
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made to Attachment 1.
Response: The GVSDT thanks you for your comment.		
Manitoba Hydro	Yes	None.
Southwest Power Pool Reliability	Yes	

Organization	Yes or No	Question 1 Comment
Standards Development Team		
Tennessee Valley Authority	Yes	
pacificorp	Yes	
Bonneville Power Administration	Yes	
Southern Company	Yes	
FirstEnergy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Luminant	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	

Organization	Yes or No	Question 1 Comment
American Transmission Company	Yes	
Wisconsin Electric Power Company	Yes	
American Electric Power	Yes	
Northeast Utilities	Yes	
South Carolina Electric and Gas	Yes	
Chelan PUD	Yes	
Exelon Corporation and its affiliates	Yes	
Georgia Transmission Corp.	Yes	
ISO-New England	Yes	

2. **The GVSDT has revised Attachment 1 to make the periodicity requirements more clear. Do you agree with these revisions? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of industry agreed that the revised Attachment 1 is clearer. There were a few minority comments about some of the specific rows in the Attachment, including proposals to refine the proxy sister unit philosophy and to move capacity factor philosophy back to the Applicability Section. However, the vast majority of industry agreed with the modified Attachment 1.

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	No	(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 3 provides guidance for early compliance and we agree that early compliance should be allowable. It establishes that 10-year period begins from the transmittal date. If a GO has data that satisfies the early compliance condition for a verified model and that data is a five years old, the Note would appear to allow the GO to transmit the data to the TP and receive credit for next 10 years effectively creating an initial 15-year re-verification cycle. Is this intended? If not, please provide more guidance for how soon the GO would have to re-verify its model. **Response: The intent of Attachment 1 Note 2 is to establish the recurring 10-year unit verification period start date assuming no consideration for early compliance. Consideration for early compliance is addressed in Note 3. This allows early compliance for a 10-year period. The 10-year period begins when model verification is specified to be "complete" per the regional policies, guidelines, or criteria that were in force. If early compliance is sought based on existing verification compliant with the requirements of this standard, as the SDT strove to write the standard such that the "how's" are specified and not the "what's," the modeling expert is expected to responsibly manage the time between the data used to verify the model and the subsequent verification and the transmittal of the**

Organization	Yes or No	Question 2 Comment
		verified model, documentation, and data to the Transmission Planner. (2) Row 4 in Attachment 1 states that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new turbine/governor and load control or active power/frequency control equipment control system. However, Requirement R4 also applies to changes to the same control system. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT feels like the distinction of a complete replacement of an governor system merits its own row in Attachment 1 as there is no doubt that this would result in the need to verify the model and is applicable to Requirement 2 and not Requirement 4.** (3) Per Requirement R4 and Row 6 in attachment 1, the GO has 180 days to submit a plan to Transmission Planner to verify the model and then another 365 days to perform the model verification date. That would appear to give the GO approximately a year and half to complete the verification for changes (including replacement) to the control system. Requirement R2 and Row 4 appear to require completion of the verification in 365 days or a year. Please modify the table or requirement to clarify appropriate application. **Response: The time lines for Requirements R2 and R4 are different as the Requirements are different. Requirement R4 specifies the need for model verification due to changes to the turbine / governor that alter the equipment response characteristic, and allows 180 days to determine if the model needs to be verified or if the submission of updated data is sufficient. Attachment 1 addresses the required periodicity and acceptable time delays to remain compliant (365 days for activities described in R4 assuming for R4 that the Generator Owner decided that they will verify the model). Conversely, R2 specifies the periodic required model verification and thus no time needs to be allotted to determine if the model needs to be verified – as it must be verified at least once every 10 years.**

Organization	Yes or No	Question 2 Comment
		Attachment 1 goes on to specify the required time or anniversary date for which verification per R2 is required.
Response: The GVSDT thanks you for your comment. Please see responses above.		
Tennessee Valley Authority	No	Attachment 1, Row Number 5, Recommend deleting “at the same physical location” from the Verification condition. The first condition is recommended to read “Existing applicable unit that is equivalent to another unit(s),” Justification is that if a GO has units that are equivalent and meet the “sister” criteria, the standard does not need to be restricted to the same physical location. The GO identical equipment at different physical locations are still equivalent.
Response: The GVSDT thanks you for your comment. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the “same physical location” requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for governor droop response vs. constant load set point) or equipment with identical design ratings, but different control system settings which would result in different models and performance).		
Consumers Energy	No	Consumers' previous comments - The generator model with the excitation system and the load rejection testing or frequency step response testing is difficult to perform and has possibilities of damaging equipment and causing reliability issues on the system in order to perform. Previous SDT reply - The GVSDT thanks you for your comment. MOD-027 is written to allow for the use of ambient monitoring, recorded data associated with the normal operation of your equipment. A GO with your concerns can alleviate the issues you mention using ambient monitoring. While we agree with the reply by the SDT when ambient monitoring is available, it is not available on all of our equipment. Therefore, we stand by our previous comments.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. Ambient monitoring can be accomplished by recording the unit's MW response, when it is in a mode in which it is expected to govern. The recordings could come from a variety of source such as from plant DCS systems, recorders, SCADA data, etc. Note that for units that need to acquire recorders, slow resolution data, approximately 1 sample per second, is adequate for turbine/governor and load control or active power/frequency control function model verification.		
Wisconsin Electric Power Company	No	In Row 5, the use of 350 MVA as the cutoff for "sister unit" treatment is not reasonable. We propose the limit can be increased to 500 MVA without any adverse reliability impacts. **Response: Based on industry comments in a previous posting, the SDT raised the proxy unit cutoff from 250 MVA to 350 MVA. This cutoff will enable the inclusion of many steam units at sites with multiple and identical CC plants. The SDT believes that it has we have achieved stakeholder consensus on the current proxy unit MVA threshold.** Also, in Row 6, the allowable time for existing units to be verified following an indication of model problems should be 2 years, rather than 1 year, since existing legacy units may require additional resources to understand and resolve the issues. **Response: The language and timing in Attachment 1 have been vetted through several comment periods. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Oncor Electric Delivery Company	No	Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP.Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support

Organization	Yes or No	Question 2 Comment
		Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Response: The GVSDT thanks you for your comment. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the functional model and the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.		
Independent Electricity System Operator	No	The long periods in Attachment 1 introduce too much risk to modeling assumptions used to assess transmission system reliability and to make other operating and planning decisions which do not reflect or address the actual performance of the system and equipment. This standard should not only establish the maximum period that Transmission Planners and Generator Owners to complete tasks but also to require the Transmission Planners to establish more stringent requirements when necessary to reduce the risk to reliability to an acceptable level. In some jurisdictions, e.g., Ontario, Generator Owners have 30 days to transmit the verified model, documentation and data to the Transmission Planner. Generator Owners are also required to indicate immediately following testing whether the installed equipment performed as expected. This approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet connection requirements. Emerging from this process is the Generator Owner's conditional right to connect provided he meets an obligation to demonstrate the installed equipment behaves as well as assumed during the assessment process. In this way, the risk to reliability is reduced to an acceptable level as the exposure of the decision making process to flawed modeling assumptions is minimized
Response: The GVSDT thanks you for your comment. The time periods in Attachment 1 have been vetted through several comment		

Organization	Yes or No	Question 2 Comment
periods. Also, performance or operational requirements and the submittal of preliminary models (typically per interconnection agreements) are beyond the scope of this standard. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Luminant	No	While Luminant agrees with the concepts in the periodicity requirements in Attachment 1, it would be beneficial for the drafting team to clearly identify that units that are base load (row 7) are excluded from model verification.
Response: The GVSDT thanks you for your comment. The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The way the non-responsive unit exemption is structured will provide for base loaded units to meet the requirement with a statement regarding the unit not responding to frequency.		
ISO-New England	No	Attachment 1, Row 4 allows for transmission of a verified model 365 days after commissioning of a new generator. This is an unacceptable length of time for a generator to be on-line from both a reliability standpoint and this length of time is in conflict with ISO/RTO Standard Generator Interconnection Agreement language. The ISO/RTO Standard Generator Interconnection language requires Generator Owners to provide verified models ***prior to*** Commercial Operation.
Response: The GVSDT thanks you for your comment. This standard does not address collection of preliminary model data from the equipment manufacturer. New equipment models cannot be verified until after the equipment is available. Generator Owner development of the original model during the equipment commissioning process – including iterations with transmission entities such as the submittal of preliminary models by the Generator Owner and modifications to preliminary model data and any requirements to verify the models prior to Commercial Operations should be governed by individual interconnection agreements.		
ExxonMobil Research and Engineering	No	No comments on this question.
FirstEnergy	Yes	Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 8 should be a part of Applicability section 4.2

Organization	Yes or No	Question 2 Comment
		Facilities. The reader of the standard shouldn't have to get to the last row of an attachment to determine as to whether a unit is exempt or not.
Response: The GVSDT thanks you for your comment. The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The way the capacity factor exemption is structured will provide for the requirement to be met with a statement regarding the capacity factor. It provides for an alternative way to meet the requirement, rather than a change in applicability. This will provide for more clarity in tracking the status for a given unit. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made to Attachment 1.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	Ingleside Cogeneration LP agrees that the explanation of the periodicity requirements are an improvement over previous versions.
Response: The GVSDT thanks you for your comment.		
Southern Company	Yes	Southern Company agrees with the modifications to Attachment 1 (the Periodicity Table) as they both simplify and clarify the periodicity.
Response: The GVSDT thanks you for your comment.		
Southwest Power Pool Reliability Standards Development Team	Yes	We would suggest that there be something added to give those GO's who have not modified their plants to be able to opt out of the re-verification. There is a concern that the updated data would be at least a year out of step with the development of

Organization	Yes or No	Question 2 Comment
		the ERAG model in the eastern interconnect.
Response: The GVSDT thanks you for your comment. The processes incorporating new model data are existing processes that have proven to work well.		
Manitoba Hydro	Yes	None.
pacificorp	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Duke Energy	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	
American Electric Power	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Chelan PUD	Yes	
Exelon Corporation and its affiliates	Yes	
Georgia Transmission Corp.	Yes	
Cowlitz PUD	Yes	

3. Do you have any other comment, not expressed in questions above, for the GVSDT?

Summary Consideration:

In the Effective Date section 5.3, the word “thirty” after the word “quarter” was inserted in the standard by mistake. As such, the SDT removed the word “thirty.” Also, in 5.1, the GV SDT changed the beginning of the first sentence from: “For Requirements R1, and R3 through R6 …“ to “For Requirements R1, and R3 through R5 …“ to reflect that there are five, not six requirements in the standard.

The wording, “… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities,” in Section 5.1 was moved to right after “… approved by applicable regulatory authorities …” And that same wording was moved to right after, “… following applicable regulatory approval …” in Sections 5.2 to 5.4. Also, the same phrase was appended to each of the four bullets in the Effective Date Section, “… in those jurisdictions where regulatory approval is required …” of the Implementation Plan right after, “… following applicable regulatory approval.” This was done to address regulatory approvals in Canada.

In the Applicability section 4.2.3, added the word “in” so that the phrase now reads, “Generation in the ERCOT Interconnection…” to be consistent with the language associated with the other interconnections (sections 4.2.1 and 4.2.2).

The SDT has refined the applicable portion of Part 2.1 to read, “Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both.” Stakeholders believed that this added clarity to the Requirement.

The footnote formatting error in R4 has been corrected.

Clarified that the response by the Transmission Planner to the Generator Owner concerning the results of testing the model useability is required to be a written response (R5). Also, for ease of reading, moved the last sentence in the requirement to after the parts.

Revised the first sentence in R1 to read, “Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request …”

Organization	Question 3 Comment
ACES Power Marketing Standards Collaborators	(1) Thank you for modifying the applicability section. It is greatly improved and is much clearer than the previous version. However, we believe there are a few additional minor refinements necessary. First, generators can be and are part of the Bulk Electric System. Thus, we suggest changing “Facilities that are directly connected to the Bulk Electric System (BES)” to “generation Facilities that

Organization	Question 3 Comment
	are part of the Bulk Electric System." Otherwise, there might be some confusion if the drafting team intends to draw in generators that are not part of the BES. Second, we find the wording "will be collectively referred as an 'applicable unit' that meet the following" confusing. We think the intent was to clarify that an applicable unit is one that is part of the BES and meets criteria established in section 4.2.1, 4.2.2, and 4.2.3. However, we think the inclusion of the "will be collectively referred as an 'applicable unit'" is superfluous. Because the section is the applicability section, we think this language could be struck for clarity and the applicable units will be understood to mean those that meet the criteria in section 4.2. As an alternative, the drafting team could explain in a footnote what they mean by the term applicable unit. Third, with the two proposed changes, we think the final wording of section 4.2 after the opening clause should be "generation Facilities that are part of the Bulk Electric System (BES) that meet the following criteria:". **Response: The SDT believes that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria. The reason for utilizing the term "applicable unit" is that it is used in other portions of the standard and allows a simple reference to the base Applicability for each Interconnection.** (2) In requirement R2, please change "for each applicable unit" to "for each of its applicable units." This is the previous wording and is more correct. The current wording literally says that the GO must provide a verified model for each applicable unit including those it does not own. After all any unit that meets applicability criteria including those owned by other GOs would be an applicable unit. **Response: The SDT believes that the use of the phrase "for each applicable unit" being placed in a sentence immediately after the phrase "Each Generator Owner shall provide" clearly conveys the intent that the applicable units being referenced are those which belong to each Generator Owner. Also, note that the term "applicable unit" is defined for the content of this standard in the Applicability section.** (3) Please specify in M1 that a Transmission Planner may also provide an attestation that no such request was received if this is the case. Use of an attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set

Organization	Question 3 Comment
	in the use of attestations in measures in FAC-003-2 M1 and M2. **Response: As you stated, compliance recognizes that an attestation is an acceptable form of evidence. As such, including that in the Measures is repetitive.** (4) We continue to believe that the examples provided in the comment form should be included in the standard. Please create an Application Guidelines or Guidelines and Technical Basis section in the standard and add them. This has become common practice with developing standards. We do not understand why the drafting team would not want to retain such information that helps readers understand the standard and that has already been developed. Furthermore, it would make it easier for commenters to see what has changed in the examples because a red-line of the standard is required. Because the examples were contained in the comment form this time and during the previous posting, it is not easy to deduce the changes because there is no red-line. If the examples are not included in the standard, please provide more explanation than was provided during the last response to comments which was that it is not appropriate to include the examples. We do not understand why it is not appropriate. **Response: The examples provided were for clarification, and the SDT does not believe that all possible scenarios are considered. The SDT does not believe the examples are appropriate for inclusion in the standard itself. Also, the sections that you referred to as being an appropriate location to include the examples are not part of this standard's format. We believe that majority of stakeholders do not have a desire to include these examples in the standard.** (5) We disagree with the need to retain the latest model verification evidence under Requirement R2 and M2. First, this is not consistent with the Section 3.1.4.2 of Appendix 3c to the NERC Rules of Procedure section which states that the audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since the audit cycle for a GO is six years and the model verification period is 10 years, the GO will have to retain data past its prior audit period. Furthermore, the auditor will have already had an opportunity to review the model verification data during the last audit. Presumably, if they did not find any compliance violations, there should not be a need to review this data again. Thus, the data retention should not exceed the six year audit cycle.

Organization	Question 3 Comment
	Response: The SDT believes that once the recurring 10-year periodicity is established, that the Generator Owner has to maintain records regarding the last verification to be able to demonstrate that they conducted a valid verification within the last 10 years. As written, this follows the Data Retention guidelines. The alternative is to shorten the periodicity to six years. However, as confirmed by industry comments in prior postings, the SDT believes that the 10-year periodicity has overwhelming industry consensus. (6) How will mothballed units be handled in Attachment 1? If a mothballed unit is returned to service which row in Attachment 1 applies? What if the unit was mothballed before the effective date and returned to service after all stages of the effective dates? What if it was mothballed after an initial verification? How does this affect the next verification date? **Response: If the unit was mothballed before the effective date of the standard, upon coming out of retirements, Row 4 would be applicable. In all cases, after the initial verification, at a minimum, the 10-year periodicity would apply. Thus, if a unit was mothballed for years 5 – 7, the model would still need to be verified with the documentation and data to the Transmission Planner at year 10.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Ameren	(1)As a general comment, NERC should make all the papers listed in the references section of the standard readily available on their website. **Response: The papers are readily available as documented in the references. Due to copyright limitations, many of the documents cannot be made available on the NERC website.** (2)There appears to be an extra word “thirty” in both redline and clean versions of the standard under section 5.3 of the Effective Date section of the draft standard. **Response: The extra “thirty” has been removed in the current draft of the standard.** (3)As we understand, part of R1 is for the Transmission Planner to provide instructions on how to obtain the list of acceptable model types for use in dynamic simulations. In this regard, we ask the SDT if this would preclude the use of user-written models?

Organization	Question 3 Comment
	Response: The standard does not preclude user written models however the model must be on the list approved by the Transmission Planner. (4)We still have serious concerns about compliance with new MOD-027-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect as explained in our response to draft MOD-026-1. We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal requirements within MOD-026 and MOD-027. This will synchronize the reporting and verification requirements and help minimize the resource burden of compliance with both efforts. At the same time it will create consistency across the country. **MOD-012 and MOD-013 contain data submittal requirements that requires submission of the latest dynamic model data for generator, excitation system, voltage regulator, power system stabilizer and turbine-governor. MOD-027 requires model verification including submittal of the verified turbine/governor model and data.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
American Electric Power	1) In Section 4.2.3, the first line should read "Generation *in* the...". **Response: The SDT has made the correction to the typo.** 2) In Section 5.3, the word "thirty" should be removed from the end of the fourth line. **Response: The SDT has made the correction to the typo.** 3) In Section B, Requirement R2 contains bold faced text stating "Error! Bookmark not defined.", is this a mistake? **Response: The SDT has made the correction to the typo (should have been a footnote).** 4) MOD-027-1 R5 ends with "...that includes the following:" yet whatever the SDT intended to follow is missing. Please note that subparts 1 through 3 are referenced in parenthetical statements within the respective requirements and that it does not make sense that these subpart criteria are also what needs to follow "...that includes the following:"

Organization	Question 3 Comment
	Response: Based on your and another commenter's input, the SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at the next to last use of the word "usable" and we moved that last sentence to after the three criteria. The last sentence now reads: If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable.
Response: The GVSDT thanks you for your comment. Please see responses above.	
Texas Reliability Entity	1) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. **Response: The SDT believes that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria.** 2) Requirement R4: Suggest removing the phrase "or plans . . ." and rewording as "Each Generator Owner shall provide revised model data for each applicable unit . . .." There appears to be a footnote error here - delete "6"? **Response: Regarding your first comment, the SDT purposely structured the requirement so that the Generator Owner has a choice of providing revised model data or plans to perform model verification – and the SDT allowed 180 days for the Generator Owner to make that determination. Regarding the second comment, the SDT has made the correction to the typo (should have been a footnote reference).** 3) TRE recommends changing to "Planning Authority or Transmission Planner" in the Functional Entities in Section 4.1.2 instead of "Transmission Planner". This change should be duplicated in the requirements. The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. **Response: The reporting structure of the standard has been vetted through multiple comment periods and the GVSDT believes that the Transmission Planner is the appropriate entity. The GVSDT believes that we have achieved stakeholder consensus on the current language of the**

Organization	Question 3 Comment
	standard.
Response: The GVSDT thanks you for your comment. Please see responses above.	
Wisconsin Electric Power Company	1. In 4.2.1.2, the use of the term "directly connected at a common BES bus" suggests that wind farms are not applicable facilities, since wind generators are typically directly connected to a non-BES bus (e.g., 34.5 kv). We suggest that the applicability to wind farms be clarified more explicitly. **Response: The SDT believes that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria.** 2. In R1, the present wording allows for the TP to provide only one of the three types of data, even if the GO requested all three. We suggest removing the wording, "one or more of". **Response: Based on your comment, the SDT revised the first sentence in R1 to read, "Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request…"** 3. In R1, the present requirement is for the TP to provide instructions to the GO on how to obtain the acceptable models and associated block diagrams and data. We believe that since the TP is very familiar with this data and the GO may not be, it is far simpler and efficient for the TP to provide the actual data on request, not just the instructions on how to obtain it. **Response: Transmission Planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner. However, the software manufacturers have indicated that they will make accommodations so that Generator Owners without software licenses can receive the block diagrams and data sheets.** 4. In R2.1.1, the GO is required to have documentation comparing the "model response" to the "recorded response", in this case MW vs. frequency. First, to determine the model response requires the ability to run dynamic studies. Generally the GO does not have the simulation capability or the subject matter experts required to perform dynamic system studies. It would seem that the intent of this requirement is that the GO must expend considerable resources to gain this capability, either internally or by other means. Is this the intent of the SDT?

Organization	Question 3 Comment
	Response: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired – or the Generator Owner can enter into agreements with its Transmission Planner, though the Generator Owner will still be responsible from a compliance perspective. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. 5. In R3, the requirements for the written response to the TP need clarification. The term "either" would suggest there are two possible responses. However, there appear to be three possible responses. We suggest there needs to be a 4th possible response option for the GO, for the GO to initiate contact with the TP to schedule a meeting to discuss the technical issues with the model. The necessary collaboration between the GO and TP to understand the model deficiencies will require time, thus may require more than the 90 days to reconcile the model issues. 120 days is suggested. **Response: The SDT believes that the sentence containing the word "either" clearly lists the three written response options afforded to the Generator Owner. Merriam-Webster dictionary defines "either" when used as a conjunction as "used as a function word before two or more coordinate words, phrases, or clauses joined usually by or to indicate that what immediately follows is the first of two or more alternatives." The SDT believes that 90 days is sufficient time to for the Generator Owner to discuss model issues with the Transmission Planner. The SDT believes all parties will be equally motivated to work through model verification issues.** 6. There is a document problem with the first sentence in R4. **Response: The SDT has made the correction to the typo (should have been a footnote reference).** 7. In Section 5 Effective Dates: The considerable time and resources needed to get up to speed with model verification suggests there needs to be more time allowed in the earlier phases of the

Organization	Question 3 Comment
	compliance timeline. We suggest using 20 percent in 4 years, 40 percent in 6 years, and 100 percent in 10 years. **Response: The SDT believes the effective dates have been well vetted in previous postings and that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Cogentrix Energy	1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1.Take for example a combined cycle plant with the CTs at base load output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc. may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to “real power response” and in R3 (3rd bull-dot) to “the recorded response” indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that” override the governor response.” Including in models only load control function blocks that impose a max-MW set point or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the

Organization	Question 3 Comment
	largest generation plants. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility)moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15,2012 FFT Order to propose specific standards or requirements that should be revised or Page 7 of 11removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF),equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. **Response: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the**

Organization	Question 3 Comment
	transmission system beyond the point of interconnection is not required for any of the verification techniques referenced in the standard. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the turbine / governor model used in dynamic simulation. Entities from 4 regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the turbine / governor model used in dynamic simulation. 2. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in comment #1 above. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. The SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it is done.** 3. There is presently no definition of how closely the model must match the recorded responseor for

Organization	Question 3 Comment
	what period of time, just a requirement that it be deemed “usable” by the TP. The SDTis asking for a blank check, and we cannot agree to regulations for which it is impossible tosay at the time of balloting whether or not compliance can be achieved, let alone in afashion that is justified per the FERC order cited above.Perceived shortcomings in these respects would presumably trigger the TransmissionPlanner expression of concern described in R3, but it would be better to establish the rulesup-front rather than addressing the matter only after a GO has attempted to comply withMOD-026 and been found lacking. . **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the term “usable” is well defined in R5. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it’s done. Note that the SDT assumed the reference cited “to comply with MOD-026…” was meant to state “to comply with MOD-027….”** 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speedgovernor reference change test, but such testing is not always possible. Where it can beattempted there is risk of creating a larger-than-desired Disturbance, possibly threateninggrid stability or tripping the generation unit. Making GOs create Disturbances if they do notnaturally occur is not a good idea. NERC should consider directing TOPs to construct loadbanks, which they can tie-in and cut-out to jar the system for response test purposes. **Response: The SDT understands and agrees that an on-line reference change test is not available on all units as an option due to the lack of an input “port” to insert a step reference change. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode.** 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may haveenvisioned rejection to house load, followed by rapid re-synchronization, but such anoutcome

Organization	Question 3 Comment
	cannot be expected. House load is often below the minimum stable output (alwaysbelow for coal-fired and nuclear plants), and it is always far below the minimumenvironmentally-acceptable load for fuel-burning units. The need to avoid over speedfollowing load rejections meanwhile generally requires that the main steam stop valves becommanded closed at the same moment that a breaker-open signal is given.Trip testing may additionally be extremely disruptive and costly. Power Technologies, intheir paper “Testing Methods, An Overview,” states that five episodes may be required,which would be enormously expensive for combined cycle plants with a fixed dollars per tripfigure written into the long-term service agreement.Page 8 of 11Such expenditures might nonetheless be justified, if the information obtained is of sufficientvalue; but, as explained in comment #1 above, trip tests will yield data only for standardgovernor models and not for the on-line extra functions for which information is evidentlybeing sought.Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offeredhowever, “Differences between the control mode tested and the final simulation model mustbe identified,” and “some method of accounting for these differences must be presented,”are too vague and constitute no solution at all. It would be better to just admit that triptesting can’t get the job done. **Response: The SDT understands that many units are not good candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]).** 6. The instruction in R4 to notify the TP, “within 180 calendar days of making changes to theturbine/governor and load control or active power/frequency control,” is too vague, despitethe attempted clarification in footnote #5, since many activities can have some degree ofimpact as noted above. Reportable thresholds regarding degree of impact on systemresponse and the expected duration are needed. Would an output power restriction due toa broken coal feeder belt be reportable, for example? **Response: The SDT believes that we have achieved stakeholder consensus on the current**

Organization	Question 3 Comment
	language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations are not practical for a standard. 7. The SDT should consider moving the capacity factor exemption information found inAttachment 1, row 8 into the applicability section. The applicability section should allow anentity to be able to determine if the standard applies to them and be able to determine thescope of the facilities affected. It is best for those impacted to immediately know which unitsare in the scope and not have to realize the scope from a detailed study of the table ofAttachment 1. This would allow row 8 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 8. We recommend removing the first element of the logical AND statement of Attachment 1Row 5 (the same physical location element). If a GO has identical equipment at differentphysical locations, they are equivalent. A sister is a sister independent of the physicallocation. As long as the equipment is identical, the concept should be allowed to applyregardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for governor droop response vs. constant load set point) or equipment with identical design ratings, but different control system settings which would result in different models and performance).**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Exelon Corporation and its affiliates	1. Exelon previously commented that MOD-027-1 R5 implies that it is the Generator Owner's responsibility to ensure that the model is "useable" based on the criteria specified in Parts 5.1

Organization	Question 3 Comment
	through 5.3; however, it is at the discretion of the Transmission Planner. As written, the requirement gives the Transmission Planner the discretion to reject the model based on governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09. Exelon again reiterates that the usability of the model should not be confused with a model that accurately represents the generating unit governor and provides projected results. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Also, the SDT believes that the Generator Owner should be positively informed from the Transmission Planner if the model is useable or not based on the criteria listed in parts 5.1 – 5.3. Also note that the Generator Owner is responsible for the model and, in accordance to the first bullet point in R3, only has to reply to the Transmission Planner if they are informed that the model is not useable. Finally, the SDT points out that the "usability" of a model does not indicate if the model accurately predicts the actual response of the equipment.** 2. Please confirm that the number of generating units combined into the percentage for implementation of unit verification includes those generating units that may have a documented exclusion such as an existing unit that does not have an installed control system. **Response: Given that this scenario is associated with Row 7 of the Periodicity Table (Attachment 1), and the Required Action column states that "Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner" then yes, it the number of generating units combined into the percentage for implementation of unit verification includes those generating units that may have a documented exclusion such as an existing unit that does not have an installed control system.** 3. MOD-027-1 R4 appears to have a formatting issue - the statement "Error! Bookmark not defined" is in bold letters within the requirement. **The SDT has made the correction to the typo (should have been a footnote reference).**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Alberta Electric System	1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more

Organization	Question 3 Comment
Operator	appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger. **Response: As discussed in the Comment Form with the first posting of the draft MOD-027 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the turbine / governor system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the turbine / governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor models, the SDT is proposing to require verification of turbine / governor associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA and kV thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. **Response: The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. As such, the SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 3. The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units. **Response: The SDT understands that many units are not candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait**

Organization	Question 3 Comment
	for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]). 4. Requirement R4, as written it appears owners of generating units that plan to change out the governor are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change. **Response: This standard addresses model verification, not the submittal of preliminary design models. Model verification can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
FirstEnergy	1.FE believes that Requirement 5 in an un-necessary requirement that the Transmission Planner must respond within 90 calendar days that the model is usable. The Transmission Planner should only respond if the information is not usable. We suggest that this requirement should be in a negative perspective and offer the following revision: R5. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 5.1 through 5.5), and shall include a technical description if the model is not usable that includes (but not limited to) the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 5.1. The turbine/governor and load control or active power frequency control function model fails to to compute modeling data without error along with suggested areas for investigation, 5. 2. A listing of parameters that fail the Transmission Planner's data checks, 5.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 5.4. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria.5.5. The turbine/governor and load

Organization	Question 3 Comment
	control or active power/frequency control model submitted by the Generator Owner is either a user defined model or a model that is not acceptable for use in the Transmission Planner's Regional Reliability Organization footprint
Response: The GVSDT thanks you for your comment. The SDT believes that the level of specificity in R5 sub parts is adequate as drafted. Based on your and another commenters input, the SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at the next to last use of the word "usable" and we moved that last sentence to after the three criteria. The last sentence now reads: If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. Also, for ease of reading, the SDT moved the last sentence in the requirement to after the parts. Also, the SDT feels that the Generator Owner should be positively informed from the Transmission Planner if the model is useable or not.	
ExxonMobil Research and Engineering	A stated purpose of Generator Verification is "to ensure that generator models accurately reflect the generator's capabilities and operating characteristics." Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets' capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load's process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load's production schedule associated with its products (e.g.,, chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same.
Response: The GVSDT thanks you for your comment. The GVSDT has used a subset of the registry criteria to identify applicable	

Organization	Question 3 Comment
Facilities. If a unit meets the sub set of the registry criteria it is obligated to comply with the standard.	
Independent Electricity System Operator	a. All references to “real” power should be changed to “active” power to follow SI standard practice. **Response: Though the term “active power’ is a SI practice, the SDT used the term “real power” to be consistent with terminology utilized in most other NERC Reliability standards.** b. One serious weakness is no there are explicit NERC performance requirements for frequency regulation. In some jurisdiction, e.g.,, Ontario, generating units are required to materially help regulate the frequency as the Transmission Planner sets performance requirements for droop, deadband and speed of response. All forms of generation are required to help regulate frequency to the extent practicable. For example, solar installations are required to reduce output during over frequency excursions. This standard in its present form allows “applicable units” to continue to not help regulate frequency could expose the BES to reliability risks. **Response: The SAR for this draft standard calls for the verification of the generator’s Turbine/Governor and Load Control or Active Power/Frequency Control Function model data. Performance or operational requirements are beyond the scope of this standard.** c. In Ontario, experience has been the models typically used by the Transmission Planner are not commonly employed by Generator Owners. The standard recognizes this in R1 by giving the obligation to the Transmission Planner to provide model block diagrams or data sheets to the Generator Owner. As the Transmission Planner may be unaware of practicable constraints on a unit and the Generator Owner may not be familiar with the reliability models, both parties must reach an accommodation on the details to verify the model. R2 should be changed so the Generator Owner is required to provide a model that has been verified by a method accepted by the Transmission Planner. If the Transmission Planner requires verification only with ambient measurements, then the Generator owner should be required to do verification in this way. This concept that the Transmission Planner should decide whether submissions it receives are suitable should permeate this standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the method used to verify the model should be determined by those doing the model verification, and that the transmission planner should only**

Organization	Question 3 Comment
	be concerned with the result, which is a correct model for the equipment. The testing expert will determine the method to use during testing and other details regarding how to do the test. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's done. d. R2.1 should be amended (see below) to add flexibility to include other practical combinations of units to be used for verification. For example, it can be more practicable to test wind and solar installation one feeder at a time but this is not allowable with the standard in its present form. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA (gross nameplate rating) may be performed using either an individual unit, a combination of units, or plant aggregate model(s). **Response: The SDT thanks you for your comment. Based on your comment, the SDT has modified the applicable portion of Part 2.1 to read: Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both** e. In Ontario, we face resistance to our standards that exceed NERC requirements. It will be very helpful if the SDT in its response offers its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, we would appreciate responses such as: "In the opinion of the SDT, having more applicable units on closed loop voltage control, reducing the time to transmit verified information to the Transmission Planner, having specific excitation performance requirements, expanding verified information to include limiters and other devices that affect excitation system performance, and making the requirements in this standard applicable to wider range of equipment are all practices that will tend to improve reliability." Or "In the opinion of the SDT, the requirements in this standard are not intended to preclude continuing or implementing more stringent Transmission Planner requirements."This type of response would help us to continue to augment the continent-wide standard with additional requirements to maintain reliability in our part of the interconnection.

Organization	Question 3 Comment
	Response: The SDT does believe that the requirements in this standard provide a floor and that individual regions or transmission entities, through venues such as interconnection agreements, can implement more stringent requirements. Unfortunately, the SDT scope is limited to drafting a national standard. f. We appreciate the SDT's effort to implement our proposed language changes to remove a potential conflict with the Ontario regulatory practice respecting the effective date of implementing approved standards. The added language, unfortunately, was not added at the appropriate places. We suggest the SDT to move the wording ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," in Section 5.1 to right after "approved by applicable regulatory approval", and move that same wording to right after "following applicable regulatory approval" in Sections 5.2 to 5.4.Also, the same phrase should be appended to each of the four bullets in the Section "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after "following applicable regulatory approval." **Response: We have made the requested edits to the Implementation Plan and Standard**
Response: The GVSDT thanks you for your comment. Please see responses above.	
American Transmission Company	ATC recommends the following changes:1. For Requirement 5, ATC recommends replacing the wording at the end of the requirement "that includes the following;" with "that includes how any of the following criteria are not met:" because the existing wording does not express that the criteria are not met when the model is not usable. **Response: Based on your and another commenters input, the SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at the next to last use of the word "usable" and we moved that last sentence to after the three criteria. The last sentence now reads: If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable.** 2. Attachment 1, Row 7, Verification Condition column - ATC agrees with the STD intention that base load units should be exempt because they are "not responsive to frequency excursion events". However, this insinuation of base load units is too vague. Therefore, ATC recommends additional

Organization	Question 3 Comment
	wording to read “New or existing base loaded units are normally not responsive to a frequency excursion event”. This makes it abundantly clear that this condition normally applies to base loaded units. **Response: The SDT believes the existing verbiage, especially the clarification in parenthesis, is very specific and unambiguous. To re-state, in order for an applicable unit to be relevant to this Row 7, the controls must be set up so that it does not operate in a frequency control mode that would result in a turbine/governor and load control or active power frequency control mode response – the exception being only during normal start up and shut down.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Idaho Power Company	Attachment 1 - Note 1Idaho Power System Planning comments Attachment 1 discusses unit model verification to a frequency excursion using a recorded response from the generating unit. Attachment 1, Note 1 defines the frequency deviation criteria. Idaho Power System Planning asks the GVSDT to include the minimum acceptable data sampling criteria of the recording equipment as part of the Note 1 criteria. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the method used to verify the model should be determined by those doing the model verification, and that the transmission planner should only be concerned with the result, which is a correct model for the equipment. The testing expert will determine the required data sampling rate and other details regarding how to do the test. The focus is solely on “what” is required, not “how” it’s done.** Requiring each Transmission Planner to maintain a list of acceptable models, and then requiring Generator Owners to submit data according to those models is unreasonable. The list of acceptable models needs to be at least regional, if not continent-wide. In addition, some required longevity needs to be specified to allow Generator Owners to appropriately plan and perform the verification work. **Response: Since the Transmission Planner is the user of the models, the models must be acceptable to the Transmission Planner in order to be deemed useful. The list of models in the**

Organization	Question 3 Comment
	vast majority of the time will be models included in major manufacturer dynamic simulation software vendor libraries and they have a high correlation with other dynamic simulation software vendor model libraries and those developed via IEEE.
Response: The GVSDT thanks you for your comment. Please see responses above.	
Cowlitz PUD	Cowlitz supports the comments from the NAGF SRT:1. The standard is based on the assumption that it is possible to tune the acceptable modelscited in R1 such that their predictions will match actual power output responses to systemDisturbances. The yet-to-be-defined acceptable models may not be capable of achievingthis goal, however, because standard governor component models are inadequate to predictwith high fidelity the generation system response that is the subject of MOD-027-1.Take for example a combined cycle plant with the CTs at base load output and the steamturbine in the sliding pressure mode (HPT control valves wide-open). Governor-only modelswill show a demand for increased output if a system frequency dip is postulated; yetabsolutely nothing will happen in real life, because the fuel input to the CTs is alreadymaxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous,with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramprates, control valve slew rate and hysteresis, the output cap associated with going VWO,furnace and duct pressure limits, fan stall run-back routines and the like all having an impacton the outcome, depending on the time-scale involved. Sustained Disturbances withfluctuations of system frequency above and below 60 Hz pose even greater challenges, asthe response characteristics of controls systems for fuel, air, drum level etc. may becometemporarily destabilized.A key clarification is needed in this respect. The references in R2.1.5 to “real powerresponse” and in R3 (3rd bull-dot) to “the recorded response” indicate that models complyingwith MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that”override the governor response.” Including in models only load control function blocks thatimpose a max-MW set point or otherwise modify the governor output signal may not pose aproblem; but the effects of all factors that cause the actual MW response to lag or otherwisevary from the governor output demand signal can be captured only by dynamic simulators,not governor models. Simulators involve enormous cost and demand on engineeringresources, and can be justified for only a handful of the largest generation plants.The SDT is therefore asking for a considerable advancement in the excitation modelingstate of the art, to

Organization	Question 3 Comment
	be undertaken in parallel by the owners of every generation unit in NorthAmerica. This is a doubly daunting task in that GOs often do not have any dynamicmodeling software or expertise, much less the ability to invent something new, because thepresent approach to the subject is that GOs just provide the values of input parameters tothe TP, which owns and runs models.Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility)moreover do not have and cannot obtain information on the system outside the plant batterylimits. This circumstance renders them unable to model the plant-T&D interactionsassociated with Disturbances, and independent GOs may therefore forever remain unable todevelop model results that closely match actual Disturbance responses.The approach being taken in MOD-027-1 is consequently viewed as being technicallyinfeasible for the present state of the art as well as unjustified in light of FERC's March 15,2012 FFT Order to propose specific standards or requirements that should be revised orremoved [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens.The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF),equipment OEMs, and modeling services vendors to develop the right tools for the job, andput the new models through trial runs at several plants. These trials should be limited todata-collection means that can be non-invasively employed (e.g., short-term on-linemonitoring, and controlled perturbations during normal-stop events), and should lead todefinition of specific testing means for definition of specific model parameters. The SDTshould then put out for voting a standard requiring TOPs to own and run these models andrequiring GOs to provide them the appropriate input data, developed via the non-invasivemeans stated above. **Response: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required for any of the verification techniques referenced in the standard. EPRI has developed software which supports**

Organization	Question 3 Comment
	non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the turbine / governor model used in dynamic simulation. Entities from 4 regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the turbine / governor model used in dynamic simulation. 2. The complexity of the task at hand is compounded by the circumstance that generation unitresponse may vary widely depending on the output level at the time a BES upset occurs (asin the combined cycle example above). There are no specifics in MOD-27-1 regarding thisaspect of reliability standard scope, however, just a requirement that the model shall matchthe actual response. The implication appears to be that a close correlation is needed for allupset magnitudes and all possible initial conditions, which brings us back to the dynamicsimulator objections in comment #1 above. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it is done.** 3. There is presently no definition of how closely the model must match the recorded responseor for what period of time, just a requirement that it be deemed "usable" by the TP. The SDTis asking for a blank check, and we cannot agree to regulations for which it is impossible tosay at the time of balloting whether or not compliance can be achieved, let alone in afashion that is justified per the FERC order cited above.Perceived shortcomings in these respects would presumably trigger the TransmissionPlanner expression of concern described in R3, but it would be better to establish the

Organization	Question 3 Comment
	rulesup-front rather than addressing the matter only after a GO has attempted to comply withMOD-026 and been found lacking. . **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the term "usable" is well defined in R5. The SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's done.** 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speedgovernor reference change test, but such testing is not always possible. Where it can beattempted there is risk of creating a larger-than-desired Disturbance, possibly threateninggrid stability or tripping the generation unit. Making GOs create Disturbances if they do notnaturally occur is not a good idea. NERC should consider directing TOPs to construct loadbanks, which they can tie-in and cut-out to jar the system for response test purposes. **Response: The SDT understands and agrees that an on-line reference change test is not available on all units as an option due to the lack of an input "port" to insert a step reference change. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode.** 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may haveenvisioned rejection to house load, followed by rapid re-synchronization, but such anoutcome cannot be expected. House load is often below the minimum stable output (alwaysbelow for coal-fired and nuclear plants), and it is always far below the minimumenvironmentally-acceptable load for fuel-burning units. The need to avoid over speedfollowing load rejections meanwhile generally requires that the main steam stop valves becommanded closed at the same moment that a breaker-open signal is given.Trip testing may additionally be extremely disruptive and costly. Power Technologies, intheir paper "Testing Methods, An Overview," states that five episodes may be required,which would be enormously expensive for combined cycle plants with a fixed dollars per

Organization	Question 3 Comment
	tripfigure written into the long-term service agreement.Such expenditures might nonetheless be justified, if the information obtained is of sufficientvalue; but, as explained in comment #1 above, trip tests will yield data only for standardgovernor models and not for the on-line extra functions for which information is evidentlybeing sought.Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offeredhowever, “Differences between the control mode tested and the final simulation model mustbe identified,” and “some method of accounting for these differences must be presented,”are too vague and constitute no solution at all. It would be better to just admit that triptesting can’t get the job done. **Response: The SDT understands that many units are not candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]).** 6. The instruction in R4 to notify the TP, “within 180 calendar days of making changes to theturbine/governor and load control or active power/frequency control,” is too vague, despitethe attempted clarification in footnote #5, since many activities can have some degree ofimpact as noted above. Reportable thresholds regarding degree of impact on systemresponse and the expected duration are needed. Would an output power restriction due toa broken coal feeder belt be reportable, for example? **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations are not practical for a standard.** 7. We recommend removing the first element of the logical AND statement of Attachment 1Row 5 (the same physical location element). If a GO has identical equipment at differentphysical locations, they are equivalent. A sister is a sister independent of the physicallocation. As long as the equipment is identical, the concept should be allowed to applyregardless of location.

Organization	Question 3 Comment
	Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for governor droop response vs constant load set point) or equipment with identical design ratings, but different control system settings which would result in different models and performance).
Response: The GVSDT thanks you for your comment. Please see responses above.	
PPL Corporation NERC Registered Affiliates	In trying to follow the flow of this standard, it is obvious that R1 precedes R2 logically. But then it also appears that possibly R5 actually takes place before R3. **Response: It is true that R5 could take place before R3. The orders of the requirements are not meant to always reflect the chronological order of events. R3 and R4 are requirements that for the vast majority of applicable units, will never be needed.** There does not seem to be any requirement for the Transmission Planner to provide Written Comments to the GO that address the second and third bullet points of R3. It seems that a requirement should be added for the TP to provide written comments for any of the 3 bullets shown in R3; however, only the first bullet of R3 has been required of the TP (in R5) as the standard is currently written in Draft 3. **Response: In the first bullet, the interaction between Transmission Planner and Generator Owner is required to ensure that the verified model is a useable model. The last two bullets are more "peer review" in nature and as such there is not a requirement for the Transmission Planner to provide a written comment. The vast majority of the time, there will be no issue with the verified model and as such there will be no need for the Transmission Planner to develop a written comment as discussed in the second and third bullet.** The first element of the logical AND statement of Attachment 1 Row 5 (the same physical location

Organization	Question 3 Comment
	element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units should be independent of the physical location. **Response: The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** Other minor edits: o In A.5.1 for the Effective Date, it should say R3 through R5 (not R6, as there is no R6). o Also, by footnote 4 on R4, there appears to be some sort of "Error! Bookmark" from when the footnotes were changed. **Response: The SDT agrees and have made these edits to the standard.** The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1.Take for example a combined cycle plant with the CTs at baseload output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of

Organization	Question 3 Comment
	controls systems for fuel, air, drum level etc may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to "real power response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW setpoint or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the generator modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated

Organization	Question 3 Comment
	above. **Response: Turbine/governor and load control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard. As stated in previous postings, the SDT recognizes that governors can react differently for events that are essentially the same depending on pre-event operating conditions – the SDT believes that the Generator Owner should strive to verify a model in such a way that it represents an approximate typical response. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required for any of the verification techniques referenced in the standard. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the turbine / governor model used in dynamic simulation. Entities from 4 regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the turbine / governor model used in dynamic simulation.** The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in our comments above.

Organization	Question 3 Comment
	Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it is done. There is presently no definition of how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the term "usable" is well defined in R5. The SDT is not requiring an on-line speed governor reference change test – it is simply an alternative. If that technique is used, experience has proven that it does not cause a disturbance that threatens grid stability. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's done.** R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. **Response: The SDT understands and agrees that an on-line reference change test is not available on all units as an option due to the lack of an input "port" to insert a step reference change. That**

Organization	Question 3 Comment
	is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid overspeed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper “Testing Methods, An Overview,” states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in our comments above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, “Differences between the control mode tested and the final simulation model must be identified,” and “some method of accounting for these differences must be presented,” are too vague and constitute no solution at all. It would be better to just admit that trip testing can’t get the job done. **Response: The SDT understands that many units are not good candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional – in fact, no positive tests are required period. All Generator Owners can choose to use the ambient monitoring technique which allows the Generator Owner to wait for a frequency excursion (per Attachment 1 Note 1) – even it takes longer than the time durations stated to wait for this frequency excursion to occur with the applicable unit operating in a frequency responsive mode (Reference Row 3 of the Periodicity Table [Attachment 1]).**

Organization	Question 3 Comment
	The instruction in R4 to notify the TP, "within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control," is too vague, despite the attempted clarification in footnote #5, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. Would an output power restriction due to a broken coal feeder belt be reportable, for example? **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations are not practical for a standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Ingleside Cogeneration LP agrees that the ability for Transmission Planners to effectively model and simulate actual system response to frequency transients can lead to reliability improvements. In addition, the technical language used in the latest version of MOD-027-1 has been refined to an acceptable point in our view. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R2) must contain language that focuses on the strength of the validation process - not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed - even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original

Organization	Question 3 Comment
	intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects.
Response: The GVSDT thanks you for your comment. Your issues relate to the "Find, Fix and Track" process that was most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states, "Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months." This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of MOD-027 are to simply verify the model and provide that model to the Transmission Planner. Under this standard, the responsible entity either performed the verification and reported it or they didn't. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.	
JEA	JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Response: The GVSDT thanks you for your comment. The GVSDT did not receive any comments from the NAGF, however others have mirrored the intent to concur with their comments (see specifically Cowlitz). We have responded to those comments above. All reliability standards undergo an economic analysis by the FERC during the NOPR process.	
Chelan PUD	Note 2, Page 4: It is unclear what would constitute and acceptable accounting - "Some method of accounting for these differences must be presented..." Unless any accounting would be acceptable, suggest some guidance.
Response: The GVSDT thanks you for your comment. Based on a review of the Field Test results and experience of the SDT members, the SDT recognized that it was not desirable to develop a dynamic model verification Standard like a technical	

Organization	Question 3 Comment
procedure manual. Such a strategy would fail as there is a wide range of equipment that will need to be verified. Thus, the SDT drafted a Standard that concentrates on "stating what is required" but without "stating how to accomplish what is required" so that the details can be managed by the modeling verification expert.	
Oncor Electric Delivery Company	Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP.Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Response: The GVSDT thanks you for your comment. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.	
Manitoba Hydro	R1 - The text would be more clear if rewritten to read 'Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner:' **The SDT revised the first sentence in R1 to read, "Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request."** 4.2 - The language immediately preceding the bullets is unclear: 'that meet the following' should perhaps be rewritten as 'provided they meet the following'. **If one removes the other parts of the sentence (stand alone phrases), the current language coveys "facilities that meet the following." The SDT believes that terminology conveys the intent. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** Effective Date Section 5.1 - Manitoba Hydro recommends changing the "R6" to "R5" because there

Organization	Question 3 Comment
	is no "R6" in the standard. **The SDT thanks you for catching this typo. The SDT has corrected the type.** General Comment - Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? **The SDT is proposed Implementation Plan allows the Generator Owner time to develop in-house expertise to perform model verification if they do not desire to hire consultants. The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes that the calculation of the percentages will be trivial, and will allow Generator Owners flexibility as compared to a "number " or "percentage" of units approach.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
ReliabilityFirst	ReliabilityFirst votes in the Negative for the draft MOD-027-1 standard since ReliabilityFirst believes there is a major disconnect/flaw between the Applicability Section (4.2. Facilities) and Requirement R2, part 2.1. This major flaw will create confusion on which generating units are required to be verified per the standard. ReliabilityFirst offers the following comments for consideration:1. Requirements R2, Part 2.1 - There is a clear disconnect between the Applicability section of the standard (i.e. individual units/plants greater than 100MVA - Eastern or Quebec Interconnections) and Requirements R2, Part 2.1 which requires"... Verification of an individual unit less than 20 MVA." Based on the Applicability section, units less than 20 MVA are not applicable under this standard. Furthermore, units under 20 MVA do not fall under the NERC Statement of Compliance Registry Criteria as criteria for registration purposes for GOs and GOPs. **Response: The intent of the SDT is to allow the model verification expert to use any combination of individual or aggregate models in the verification of plants. The SDT has modified the applicable portion of Part 2.1 to read, " Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both."**

Organization	Question 3 Comment
	2.Applicability Section 4.2. Facilities - ReliabilityFirst thanks the SDT for their justification for the 100 MVA threshold, but still believes that the Applicability should be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). Even though the 100 MVA threshold covers 80% of the connected MVA or greater for each Interconnection (in aggregate), depending on the geographic location (within the BES), that value may be much less. For example, if there is a certain load pocket in which the majority of the connected generation is lest that 100 MVA, the dynamic models would not be required to be verified per this standard. Thus not having verified accurate dynamic models for this specific location could hinder the reliability of the BES. ReliabilityFirst recommends changing the Applicability section to be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). **Response: As discussed in previous postings of the draft MOD-027 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by**

Organization	Question 3 Comment
	dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Also, the SDT does recognize that Regional variances can be considered if a Region desires to include additional unit MVA in this standard.
Response: The GVSDT thanks you for your comment. Please see responses above.	
Seattle City Light	Requirement 2.1.1 states three separate ways to verify MW response for a synchronous generator, but uses the term "either of" when referring to the choice of tests, which implies two tests. Please clarify with either two tests or change the reference to "any of." In addition, one of the tests of 2.1.1 includes a partial load rejection. Such a test is already part of the Kestrel test procedures currently performed by Seattle City Light. It is not clear from the requirement and footnote if our existing test would be sufficient for validation or if the other two tests would also be required. Please clarify the language of R2.1.1.
Response: The GVSDT thanks you for your comment. The use of a bullet lists in R2.1.1 conforms to standard development protocol. Specifically, a bullet list indicates the entity selects which of the listed actions is appropriate to perform. Additionally the use of the phrases "either" at the end of the root requirement, followed by a comma at the end of the first bullet, the word "or" at the end of the second bullet emphasizes that one of the three test results can be utilized. Only one of the three bulleted activities has to occur for compliance – as such, if an entity has utilized a partial load rejection test and satisfied the corresponding footnote, then that would satisfy what is required from R2.1.1. For the above stated reasons, the SDT believes that it has achieved stakeholder consensus on the current language of the standard.	
Dynegy	Some smaller Generator Owners have little experience in this type of testing. If possible, it is suggested more detail be placed in Attachment 1 regarding what constitutes an acceptable test, i.e., template.
Response: The GVSDT thanks you for your comment. Based on a review of the Field Test results and experience of the SDT members, the SDT recognized that it was not desirable to develop a dynamic model verification Standard like a technical procedure manual. Such a strategy would fail as there is a wide range of equipment that will need to be verified. Thus, the SDT	

Organization	Question 3 Comment
drafted a Standard that concentrates on "stating what is required" but without "stating how to accomplish what is required" so that the details can be managed by the modeling verification expert.	
Tennessee Valley Authority	Step 4.2.3, Recommend adding "in" to the requirement to read "Generation in the ERCOT Interconnection ..." Justification is to be consistent with similar steps 4.2.1 and 4.2.2.
Response: The GVSDT thanks you for your comment. The SDT has corrected the typo.	
Northeast Power Coordinating Council	Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. **The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes this is a clear designation that the thresholds are determined by the percent of unit gross MVA and not by the number of devices. This does mean that the total applicable unit MVA per Interconnection, as specified in Section 4.2 (Applicability / Facilities) will have to be determined by the Generator Owner. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment.	
Southern Company	The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 8 of Attachment 1 to be deleted.

Organization	Question 3 Comment
	Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The way the capacity factor exemption is structured will provide for the requirement to be met with a statement regarding the capacity factor. It provides for an alternative way to meet the requirement, rather than a change in applicability. This will provide for more clarity in tracking the status for a given unit. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Requirement R4 has a problem with the bookmark "Error! Bookmark not defined". **Response: Thank you for pointing out this error. The footnote designation has been corrected.** We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service).**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Dominion	There appears to be a mismatch between Requirement R2 and the Effective Date statements. Specifically, R2 is applied on an "applicable unit" bases where the Effective Date statements are applied on an "applicable unit gross MVA" basis.R4; **Response: The language in R2 refers back to the Applicability / Facilities definition of "applicable unit." The effective dates determine the quantity of units to be verified for each Effective Date –**

Organization	Question 3 Comment
	and that quantity is based on an "applicable unit gross MVA" basis. bookmark #4 in the clean version needs to be corrected, shows 'Error! Bookmark not defined. **Response: Thank you for pointing out this error. The footnote designation has been corrected.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Utility Services	Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comment. The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes this is a clear designation that the thresholds are determined by the percent of unit gross MVA and not by the number of devices. This does mean that the total applicable unit MVA per Interconnection, as specified in Section 4.2 (Applicability / Facilities) will have to be determined by the Generator Owner. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.	
NIPSCO	Verification requirements would be burdensome, e.g., model response by a load rejection test or comparison with a system frequency excursion may be of only limited value. Another basic problem with this standard is the unnecessary back and forth between generation owners and transmission planners in the data development and collection. This standard could be greatly simplified for all involved parties with reporting requirements similar to MOD-025 where the generation owner provides information to the transmission planner upon the installation of new equipment or the modification of existing equipment. Given the above, Transmission Planning recommends a vote against this standard in its present form.

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comment. The SDT believes peer review is an essential part of the model verification process irrespective of criteria or guidelines available from industry since peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. This peer review process is not necessary for the validation of unit steady state parameters, but is necessary for dynamic model verification to ensure accurate models that are compatible with dynamic simulation programs. Note that the use of load rejection test is only an option that does not have to be utilized by the Generator Owner. Also, the SDT believes that the recording of units real power output while they are in operating in a frequency responsive mode during a system frequency excursion that meets or exceeds the criteria in Attachment 1 Note 1 is of great value and can be used to verify the model. Finally, The SDT understands that many units are not good candidates for partial load rejection tests for the purposes of governor model verification. That is one of the reasons why this test is optional.	
Duke Energy	We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units is independent of the physical location.
Response: The GVSDT thanks you for your comment. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service).	
PSEG	We voted "Negative" on this standard the reasons shown below:This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1.1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a "team" with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as "applicable facilities," while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments:"The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree)

Organization	Question 3 Comment
	states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.”The SDT responded as follows:”The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.”In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses:MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.”PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.”We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. **Response: Note that modeling of synchronous condensers is not applicable to MOD-027. Synchronous condensers are implemented for dynamic voltage control and are not part of any turbine/governor equipment.** SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1.2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1 R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all “modelers,” the result will be outdated data in someone’s model, which can have a bad result. The team should have one broad “data sharing” policy in the three MOD

Organization	Question 3 Comment
	standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it. **Response: The GVSDT has written the requirements of this body of standards based on the NERC Reliability Functional Model. The requirements of Reliability Standards MOD-010-0. MOD-011-0, MOD-012-0 and MOD-013-1 address the requirement for steady state and dynamic models (which are planning models) and the dissemination of these models to appropriate entities. The data to build Real-time models that are necessary for reliability and used by Reliability Coordinators and Transmission Operators are addressed in standards IRO-010-1a and TOP-003-2 respectively. The GVSDT does not see any reason to include duplicative requirements in this standard. There are already processes in place which facilitate the sharing of the most current dynamic models through MOD-012 and 013. In the eastern interconnection, dynamic models are shared in part through the MMWG.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
ISO-New England	Attachment 1, Row 8 has a reference to capacity factor. The capacity factor section has been removed from the body of the standard. If the capacity factor is still part of the standard by it's existence in the Attachment then this is unacceptable. Older large units with low capacity factors will be called upon to operate during extreme weather events when the system is most stressed. System reliability will be compromised if the modeled characteristics of the units differ from what is actually installed in the field. **Response: The SDT believes that there is little reliability to be gained by testing units with capacity factor of less than 5%. The added cost of testing is not justified. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** Requirement R1 may bring out some concern over the copyrighted models supplied by the simulation software vendors. Hopefully this can be worked out with the vendors. **Response: The software manufacturers have indicated that they will make accommodations so**

Organization	Question 3 Comment
	that generator owners without software licenses can receive the block diagrams and data sheets. Requirement R3 might only require a "written response" from a Generator Owner to the Transmission Planners notification that a model is not useable with some technical basis for keeping the current model that is not usable. Wording must be included so that ultimately the Generator Owner shall provide a "usable model" to the Transmission Planner. **Response: Requirement R3 is a "peer review" type requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to request the Generator Owner to review the data and assist in identifying problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process was over whelming supported by Industry based on their responses in prior postings.** Requirement R5 sub-requirement wording should be changed to indicate the Transmission Planner shall notify the Generator Owner if the excitation model *does not* initialize, a no-disturbance simulation results in transients or a disturbance simulation results in a model exhibiting negative damping. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Also, the SDT feels that the Generator Owner should be positively informed from the Transmission Planner if the model is useable or not.**
Response: The GVSDT thanks you for your comment. Please see responses above.	

END OF REPORT

Consideration of Comments

Project 2007-09 Generator Verification
PRC-019-1

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to PRC-019-1. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 47 sets of comments, including comments from approximately 153 different people from approximately 99 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Summary Consideration

A large majority of stakeholders agree with the change in the VRF revisions and no stakeholder provided comments suggesting that they should be further revised.

A large majority of stakeholders agree with the revised VSLs. The GVSDT received one suggestion for revisions but the team felt that the proposal would add confusion rather provide further clarity to the VSLs.

Based on the stakeholder comments below, the GVSDT made the following minor edits and clarifications to the standard:

- Added specific language to the Effective Date section to clarify that certain regulatory bodies approve standards differently.
- Changed “AVR” to “automatic voltage regulator” in Requirement R1 (AVR is not a defined term).
- Removed the word “review” from Measure M2.
- Added a reference in Section F for IEE C50.13-2005.
- Removed "Converter Over-temperature limiter and associated protection function" from the example of Section G (Reference Information) because it is not a element that can be coordinated.

Index to Questions, Comments, and Responses

1. The GVSDT revised the VRFs to "Medium" based on stakeholder feedback. Do you agree with the proposed revision? If not, please provide an alternative and supporting information in the comment area below. 12
2. The GVSDT revised the VSLs for each requirement based on stakeholder feedback. Do you agree with the proposed revisions? If not, please explain in the comment area below. 15
3. Do you have any other comment, not expressed in questions above, for the GVSDT? 19

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Domion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	John Allen	City Utilities of Springfiel	SPP	1, 4
3.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
4.	Sean Simpson	Board of public utilities of kansas city	SPP	1, 3, 5
5.	Mark Wurm	BPUK	SPP	NA
6.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
7.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
8.	Brian Taggert	Westar Energy	SPP	1, 3, 5, 6
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	John Mayhan	Omaha Public Power District	MRO	1, 3, 5
11.	Ron McIvor	Omaha Public Power District	MRO	5, 1, 3
12.	Mahmood Safi	OPPD	MRO	1, 3, 5
13.	Anna Wang	Burns McDonald	SPP	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10. David Kiguel	Hydro One Networks Inc.	NPCC	1
11. Michael Lombardi	Northeast Utilities	NPCC	1
12. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13. Bruce Metruck	New York Power Authority	NPCC	6
14. Robert Pellegrini	The United Illuminating Company	NPCC	1
15. Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17. Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19. Brian Robinson	Utility Services	NPCC	8
20. Michael Schiavone	National Grid	NPCC	1
21. Wayne Sipperly	New York Power Authority	NPCC	5
22. Donald Weaver	New Brunswick System Operator	NPCC	2
23. Ben Wu	Orange and Rockland Utilities	NPCC	1
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Ian Grant		SERC	3
2. Marjorie Parsons		SERC	6
3. David Thompson		SERC	5
4. Dewayne Scott		SERC	1
5. Tom Vandervort		SERC	5
6. Annette Dudley		SERC	5
7. Paul Palmer		SERC	5
8. Goerge Pitts		SERC	1
9. Robert Bottoms		SERC	
10. David Marler		SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Burns	Technical Operations	WECC	1
2. Chuck Matthews	Transmission Planning	WECC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
3.	Erika Doot	Generation Support	WECC	3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Steve Kern	FE Energy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	paul haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel	krupa	WECC	1
2.	dana	wheelock	WECC	3
3.	hao	li	WECC	4
4.	mike	haynes	WECC	5
5.	dennis	sismael	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Frank Gavvney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	E Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Jackson	MEAG Power	SERC	3
2.	Steve Grego	MEAG Power	SERC	5
3.	Danny Dees	MEAG Power	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Thomas McElhinney	JEA	X		X		X					

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	John Shaver	Southwest Transmission Cooperative	WECC	1
3.	Tom Alban	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	James Manning	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection

NERC

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
	1. Central Electric Power Cooperative	SERC	1, 3										
	2. KAMO Electric Cooperative	SERC	1, 3										
	3. M & A Electric Power Cooperative	SERC	1, 3										
	4. Northeast Missouri Electric Power Cooperative	SERC	1, 3										
	5. N.W. Electric Power Cooperative, Inc.	SERC	1, 3										
	6. Sho-Me Power Electric Cooperative	SERC	1, 3										
16.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
17.	Individual	David Thorne	Pepco Holdings Inc and Affiliates	X		X							
18.	Individual	ryan millard	pacificorp	X		X		X	X				
19.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
20.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
21.	Individual	Nicole Buckman	Atlantic City Electric Company			X							
22.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
23.	Individual	Mark Yerger	Potomac Electric Power Company			X							
24.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
25.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
26.	Individual	Winnie Holden	PSEG	X		X		X	X				
27.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
28.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)					X					
29.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
30.	Individual	Saul Rojas	New York Power Authority	X		X		X	X			X	
31.	Individual	Thad Ness	American Electric Power	X		X		X	X				
32.	Individual	Michael Falvo	Independent Electricity System Operator		X								
33.	Individual	Wryan Feil	Northeast Utilities	X									
34.	Individual	Brian Evans-Mongeon	Utility Services								X		
35.	Individual	Daniel Duff	Liberty Electric Power LLC					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
36.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
37.	Individual	Scott Berry	Indiana Municipal Power Agency										
38.	Individual	John Martinsen	Snohomish County PUD No.1	X		X	X	X	X			X	
39.	Individual	Mike Hirst	Cogentrix Energy					X					
40.	Individual	Mary Downey	City of Redding			X	X	X	X				
41.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
42.	Individual	Kirit Shah	Ameren	X		X		X	X				
43.	Individual	Don Jones	Texas Reliability Entity										X
44.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
45.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
46.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
47.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Supporting Comments of "Entity Name"
MEAG Power	Southern Company Services, Inc. - Gen
Delmarva Power & Light Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Atlantic City Electric Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Potomac Electric Power Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Liberty Electric Power LLC	NAGF
Snohomish County PUD No.1	Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Indiana Municipal Power Agency	Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum for PRC-019.
City of Redding	SMUD/BANC
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

1. **The GVSDT revised the VRFs to "Medium" based on stakeholder feedback. Do you agree with the proposed revision? If not, please provide an alternative and supporting information in the comment area below.**

Summary Consideration: A large majority of stakeholders agree with the change in the VRF.

The consensus of stakeholders submitting comments was that an assignment of Medium VRFs was appropriate.

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative, Inc. - JRO00088	No	AECI does not believe R1 should exist as currently drafted, see below.
Response: The GVSDT thanks you for your comment. The comment does not address the question asked. Please see the response to your comment in Question 3 below.		
Cowlitz PUD	No	Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
Response: The GVSDT thanks you for your comment. The GVSDT is required to assign VRF's as part of the drafting process.		
Manitoba Hydro	Yes	None.
PPL Corporation NERC Registered Affiliates	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc and Affiliates	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
FirstEnergy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Luminant	Yes	
ACES Power Marketing Standards Collaborators	Yes	
pacificorp	Yes	
Southern Company	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)	Yes	
American Transmission Company	Yes	
American Electric Power	Yes	
Wisconsin Electric Power Company	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 1 Comment
New York Power Authority	Yes	
Northeast Utilites	Yes	
Omaha Public Power District	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Exelon Corporation and its affiliates	Yes	
Texas Reliability Entity	Yes	

2. **The GVSDT revised the VSLs for each requirement based on stakeholder feedback. Do you agree with the proposed revisions? If not, please explain in the comment area below.**

Summary Consideration: A large majority of stakeholders agree with the revised VSL's.

Organization	Yes or No	Question 2 Comment
Ameren	No	(1)Although we prefer a % of Facilities approach, we can accept the R1 VSL revision with the stated time frames. **Thank you.** (2)A time-based VSL does not align with the severity of failing to meet R2. The severity is primarily a function of the amount of on-line exposure. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. We request that for R2 the SDT replace the time-based (days late) with % of MWh during the period of violation to more properly account for aggregate impact and restate the R2 VSL as follows:(a)Lower VSL becomes 'The Generator Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing from 0% to 5% of their total MWh generated during the violation period.' This does require each unit to be coordinated. (b)Moderate VSL becomes '...more than 5% and less than 10%' (c)High VSL becomes '...more than 10% and less than 15%'(d)Severe VSL becomes '... more than 15%'.(3)We request that the SDT insert 'latter of' before 'identification or implementation' in R2 VSL if the SDT does retain the time-based VSL format. Identification differs from implementation so clarity is needed if a violation does occur. **Using a structure as suggested does not meet the NERC guidelines for VSL development. In addition, the GVSDT believes this would be much more complex to administer. No change made.**
Response: The GVSDT thanks you for your comment. See response to specific comments above.		

Organization	Yes or No	Question 2 Comment
Cowlitz PUD	No	Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
Response: The GVSDT thanks you for your comment. The GVSDT is required to develop VRF's and VSL's as part of the drafting process.		
seattle city light	No	New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Response: The GVSDT thanks you for your comment. The GVSDT believes there is a reliability benefit to reviewing coordination every five years because limiter and protection settings may be changed by somebody other than the person responsible for the coordination review and the effective system impedance (which affects the SSSL) may easily change without the Generator Owner's knowledge.		
Manitoba Hydro	Yes	None.
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc and Affiliates	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Luminant	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
ACES Power Marketing Standards Collaborators	Yes	
pacificorp	Yes	
Southern Company	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)	Yes	

Organization	Yes or No	Question 2 Comment
American Transmission Company	Yes	
American Electric Power	Yes	
Wisconsin Electric Power Company	Yes	
Independent Electricity System Operator	Yes	
New York Power Authority	Yes	
Northeast Utilites	Yes	
Omaha Public Power District	Yes	
South Carolina Electric and Gas	Yes	
Exelon Corporation and its affiliates	Yes	
Texas Reliability Entity	Yes	

3. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

Summary Consideration: Based on the stakeholder comments below, the GVSDT made the following edits and clarifications to the standard:

- **Added specific language to the Effective Date section to clarify that certain regulatory bodies approve standards differently.**
- **Changed "AVR" to "automatic voltage regulator" in Requirement R1 (AVR is not a defined term).**
- **Removed the word "review" from Measure M2.**
- **Added a reference in Section F for IEE C50.13-2005.**
- **Removed "Converter Over-temperature limiter and associated protection function" from the example of Section G because it is not a element that can be coordinated.**

Organization	Question 3 Comment
ACES Power Marketing Standards Collaborators	(1) R1 should be modified to clarify that the GO or TO shall coordinate their applicable Facilities. While most readers would interpret the requirement to apply to the Facilities owned by the GO and TO, it simply does not say this. We recommend using "each GO and TO shall coordinate the voltage regulating system controls ... applicable equipment capabilities of its applicable Facilities and the settings of the applicable Protection System devices and functions." **The GVSDT believes that the applicability section adequately prescribes the scope of the facilities and declines to make this change.** (2) While we disagree with the inclusion of blackstart units in this standard, the previous wording was actually more correct and consistent with the Statement of Compliance Registry Criteria. Changing "Blackstart Resource" to "blackstart unit" only causes confusion and ambiguity. By definition a "Blackstart Resource" is a blackstart unit that is included in the Transmission Operator's restoration plan. Since the applicability section also states that the blackstart unit must be included in the TOP's restoration plan, it is not clear what was accomplished with changing Blackstart Resource to blackstart unit. It causes the reader to question what additional units are intended if

Organization	Question 3 Comment
	they don’t mean Blackstart Resource. Furthermore, it deviates from the wording in the Statement of Compliance Registry Criteria. This is contrary to the response that was provided to a comment by PSEG to change the language during the last posting. The response indicated that the “SDT feels it is best to retain the NERC wording without modification.” We can find no other citation in the response to comments indicating a reason to change it. Please change blackstart unit back to Blackstart Resource. **The compliance registry criteria V5 document, paragraph III.c.3 is shown below….** III(c) Generator Owner/Operator: III.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or; III.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating, or; III.c.3 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity’s restoration plan, or; III.c.4 Any generator, regardless of size, that is material to the reliability of the bulk power system. **Section 4.2.4 of the draft standard matches this registry criteria wording exactly.** (3) In applicability sections 4.2.1 through 4.2.3, please change “directly connected to the BES” to “that are part of the BES”. Per the BES definition, generation units can be and are part of the BES. Using “directly connected to the BES” could draw in a non-BES unit. **The existing wording more closely matches V5 of the registry criteria and will be retained.** (4) There is an extraneous comma in R2.

Organization	Question 3 Comment
	The sentence structure has been altered slightly to address this concern.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Ameren	(1)R2 is unclear as written, please insert 'latter of' before 'identification or implementation' to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. **The GVSDT believes that the existing wording is adequate to ensure that the protection elements are coordinated.** (2)Attachment 1 Example appears to violate R1 1.1.2. Loss of Field Zone 2 trips before 'operating conditions exceed equipment capabilities.' On the other hand, it would certainly 'limit the extent of damage when operating conditions exceed equipment capabilities or stability limits' since it trips before either of them are reached. This example does show how specialized and complex this coordination is. Entities may have different margins, asset protection, and operating practices. We presume the SDT intends that the examples show 'coordinated' capabilities, controls, and protection. If not, the lack of coordination should be pointed out. **The coordination shown in the example of Attachment 1 is simply that: an example of a system demonstrating the coordination of the settings with respect to an example protection philosophy. This draft standard does not specify margins, asset protection limits, or operating practices. Entities are obligated to review the protection elements to ensure that gross errors do not exist which may result in undesired premature tripping or extensive damage to equipment which contributes to the reliability of the power system.** (3)We request that the GVSDT make all the papers listed in the reference section of the standard readily available on the NERC website. **Copyright laws do not permit this publication the references provided should provide adequate information to allow entities to obtain copies of the documents.**

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Florida Municipal Power Agency	1) R1 can be misinterpreted to require a full-blown coordination study every 5 years even if nothing at the plant had changed. There should be a qualifier saying that past coordination studies are still valid if nothing has changed, but that at minimum a review is needed every 5 years to see if the existing coordination study is still valid. **A previously completed coordination study can be used as a baseline or starting point for this recurring requirement. If nothing has changed in the system since the previous coordination, the required action could amount review and confirmation of the previously determined coordination.** 2) A synchronous condenser can be owned by either a TO or GO. For instance, there are installations of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO who owns a synchronous condenser. **Draft standard sections 4.1.1 and 4.2.2, taken together, make this standard applicable to GO's with synchronous condensers.**
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Texas Reliability Entity	1) Does the SDT foresee any conflicts between the proposed language in PRC-019-1 and the proposed setting limits in PRC-025-1, Generator Loadability? **There appears to be industry concern over the "relaxed" protection thresholds currently specified in the draft PRC-025 standard with regard to minimizing equipment damage from overloads. R1.1.1 of the draft PRC-019 has the same objective as PRC-025.** 2) The SDT may want to include a reference ANSI C50.13-2005 for proper coordination of the over/under excitation limiters with AVR, equipment capabilities, and loss-of-field, and other

Organization	Question 3 Comment
	protective functions. **As the referenced document contains design rating considerations for cylindrical-rotor synchronous generators rated 10MVA and above, it can be a useful document when performing the proposed requirements of this standard. It will be referenced in the associated documents section F.** 3) Measure M1: Evidence should also include documentation that actual settings for relays, AVRs, and limiters match the coordination study. **This is superfluous and not necessary. The coordination plots, settings table comparisons, or other methods used to verify coordination are visual representations of the settings that reside in the protective devices. They, by definition, are the same as the actual settings. Otherwise, the coordination studied is not a review of the coordination which is specified in R1 of the draft standard.** 4) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. **Until the BES definition document is completed, any change to the applicability section of this draft standard is premature. The applicability section of this draft standard matches, very closely, the verbage of version 5 of the NERC Statement of Compliance Registry Criteria, section IIIc.** 5) In general, the Protection System changes should be coordinated before energization (or re-energization) following a change. Is the 90 day time period in R2 consistent with the expectations of PRC-001? **That is true, in general. Utilities generally will not commission new protective relaying without consideration of the application of appropriate settings for the devices. Without this consideration, the protection equipment will either not provide adequate protection or will trip**

Organization	Question 3 Comment
	the equipment premature to necessity. The GVSDT believes that requirements R1 and R2, as drafted, are adequate to confirm that the proper coordination exists. Rather than detailing every possible change which can affect the coordination and specifying timelines for compliance for each type of change, the drafting team elected to present the requirement as provided.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Duke Energy	1) Section 1.1: Reword to clarify "normal" is describing the AVR control mode only. Also, SDT should consider mentioning weak system operating conditions are typically used when coordination with the SSSL. Suggested rewording: “Under steady-state system operating conditions, and assuming normal AVR control loop conditions, verify the following coordination items for each applicable Facility:” **“The” was added to R1.1 to emphasize that normal applies to the AVR control mode.** 2) Section 1.1.2: Strike this section, as it is outside the scope of this document. It appears to be mandating protection. PRC-019-1 should be focused on settings. **The words “applicable, in-service” qualify that an entity must consider minimizing the extent of damage to equipment through the settings of protection that he has elected to place in-service. The requirement does not dictate that such protection be placed in-service.** 3) Page 7/11: (Reword 2nd paragraph) Examples of limits, limiters, protection which must be coordinated if employed include: **As this section is simply a section indicating examples of the types of protective functions which may be applied on a generating unit. The NOTE in this section specifies that this section is for reference only, and does not specify additional requirements. The use of “must be coordinated if employed” is not appropriate for an example section. The requirement for inclusion of protective elements which are in service is located in R1, where it should be located.** 4) Page 7/11: Remove all the words "associated" in second paragraph. **The GVSDT believes that “associated” is necessary in this paragraph to make it clear that the protective functions listed in each line item are those that are associated with a particular**

Organization	Question 3 Comment
	protective function. 5) Page 7/11: Remove section on SSSL calculation. Does not belong in standard, see references listed as needed. **This section was added during a previous revision to this standard at the request of multiple commenters.** 6) The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. **The coordination review, practically, should be done just prior to the reactive testing specified by MOD-025 so that the protection does not operate undesirably during the testing. The applicability of PRC-019 and MOD-025 are set to match each.** 7) The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. **The GVSDT believes that 5 years is a more appropriate interval for this review.** 8) Strike "Convertor Overtemperature" from this list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. **The standard has been revised to address your concern.** 9) R2 specifies "perform the coordination" while M2 states "coordination review" - we believe that R2 and M2 should be consistent. **The standard has been revised to remove "review" from R2 and M2.**
Response: The GVSDT thanks you for your comment. Please see specific responses above.	

Organization	Question 3 Comment
Wisconsin Electric Power Company	1. In R1.1.2, we suggest revising the sentence to : "The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage...". **The GVSDT slightly modified this statement to state the requirement more clearly.** 2. In R1, there needs to be a way for entities to take credit for coordination studies done in the last 2 years prior to the effective date of this standard. **There is no wording to prevent this. Once the standard is in effect, the entity must have 40%, 60%, 80%, and 100% of their applicable units compliance in two years, three years, four years, and five years, respectively. The entity can choose the scheduling order. If an entity has already completed coordination studies and has evidence to prove it at the time of the effective date of this standard, then (barring no changes that invokes R2) they need only to review the coordination before the 5 year time frame to maintain compliance with R1.** 3. In R2, the 90 day requirement to document coordination following a change is not reasonable. It may not be possible to obtain the necessary information from equipment vendors in this timeframe. We suggest a time of 180 days for this requirement. **The GVSDT believes that the 90 day time frame is adequate.** 4. It is not clear how these requirements would be satisfied at wind farms. None of the example information in Section G Reference appears to be applicable to wind farm equipment. We suggest that wind resources be specifically exempted from this standard.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Cogentrix Energy	1. R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, **The GVSDT has revised the standard in an attempt to ensure that coordination of the protection system will occur. If no changes have occurred, a review of the previous coordination will suffice.**

Organization	Question 3 Comment
	2. It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1. **The GVSDT believes that the draft standard adequately prescribes that only those elements which are in service are subject to being included into the coordination study. Also, please see the NOTE on p7 of Draft 3 of the draft standard with regard to not requiring installation or activation of limiters or protective functions.** 3. The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. That is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. **The listing provided in section G is not meant to be prescriptive. It is to be used for example only. The NOTE in that section reflects this. The phrasing in paragraph 2 of page 7, "limiters and protection functions which could be coordinated include (but are not limited to). The list is representative of functions which typically are found in excitation control systems. Only those functions which are in service (at the choice of the entity) need to be addressed in response to this standard.** 4. The term "black start unit material" in applicability para. 4.2.4 (p.2) is not understood. We would object if the intent was to designate any unit that has the potential for black start capable conversion, in addition to units that are presently black start resources. GOs would, in this case, have to take on substantial burdens based on mere conjecture as to modifications that might (but probably would not) be made sometime in the future. **The wording used in applicability section 4.2.4 is taken directly from V5 of the NERC Statement of Compliance Registry Criteria, and clearly states that the units addressed here are those which are designated in the transmission operator's restoration plan.** 5. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in our possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable.

Organization	Question 3 Comment
	PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. **For protective relay settings to be determined, some type of analytical comparison must be used to achieve coordination. Specifying that this documentation be included with any resultant relay settings or excitation system protection parameter settings should not add any considerable cost. The additional cost is simply including some documentation of the comparison method used to determine the relay/excitation control settings.** 6. The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. **The GVSDT believes that the five year interval is more appropriate for PRC-019 and MOD-025.** 7. It is suggested to strike “Convertor Over temperature” from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not an element that can be coordinated. **The standard has been revised to address your concern.** 8. R2 specifies “perform the coordination” while M2 states “coordination review” - we suggest that R2 be changed to “review the coordination” **The standard has been revised to ensure that the protection system is coordinated.**
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Tennessee Valley Authority	1. Reference, Examples of Coordination, page 7 of 11, bullets at the top of page 7, Recommend deleting the word “associated” in all of the applicable bullets. Justification is that the word “associated” is not needed in these bullets and it will make the bullets more crisp. **The drafting team believes that the phrase “and associated protective functions” is necessary to suggest that those limiters have protective functions that require coordination. It is the responsibility of the entity to illustrate coordination between these limiters and their**

Organization	Question 3 Comment
	associated protective functions while maintaining generator equipment protection. 2. Standard, 4.2 Facilities, The unit size applicability for PRC-019-1 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027-1 (i.e. MOD-026-1 Draft, 4.2, Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ... (including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ... (including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ... (including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.) **The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.** 3. Requirement R1, Recommend changing the periodicity of this verification as stated "At a maximum of every five calendar years, ... " to a recommended verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, "6 calendar years." Justification is to coordinate protective system relay testing during plant outages with the voltage regulating controls and protections testing that can be performed during outage shut-down or start-up sequences. **The GVSDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection**

Organization	Question 3 Comment
	settings of generating equipment, the GVSDT feels that a five year verification of this characteristic is appropriate.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Independent Electricity System Operator	1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by:a. In the Implementation Plan, under the Section "In those jurisdictions where regulatory approval is required:", adding a phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner..."b. In Section A5.1 of the standard, adding the same phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner...". **The GVSDT agrees to change the Effective Date wording to address your concerns. After consultation with NERC legal counsel, the following wording has been added: "… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."** 2. The wording of R1 is confusing, since the required coordination shall be maintain all the time. We suggest a change of the wording as follows: the phrase "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls" should read "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall review the coordination of the voltage regulating system controls" ; Also, the phrase "1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily." should read" 1.1.1. The in-service voltage regulating control limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily."

Organization	Question 3 Comment
	The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the wording at this time.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Associated Electric Cooperative, Inc. - JRO00088	Applicability, Part 4.2.4, CHANGE: Remove this entire clause specific to Blackstart of units of any size, RATIONALE: AECI agrees with earlier Industry commenters that opposed the inclusion of these units and disagrees with the SDT's persistent inclusion. Inclusion of Blackstart units of any size, ultimately harms the grid reliability by imposing more regulatory-risk exposure upon them, such that our industry is already seeing many disappear from system restoration plans. With this trend left unchecked, and we are trying to piece our systems back together 10 years from now for whatever reason, the RCs will not even know that many of these viable units still exist. Many may have in fact been driven from existence by such well-intentioned laws having failed to consider the unintended consequences. In addition, the value of AVR functionality for Blackstart units is highly questionable during blackstart situations. **The GVSDT disagrees that Blackstart Resources should be removed from the applicability of this standard. When called upon to operate in their black-start mode, it would probably be under stressed transmission system conditions that could require the generator to provide reactive power to its limits (either leading or lagging). Given the critical nature of an actual transmission system recovery, having the black-start generator limiters and protection properly coordinated is essential.** Requirement R1, CHANGE: Redraft the language toward each responsible entity's internal controls program, RATIONALE: While AECI appreciates the initial 5-year time-line to "check the coordination of all our unit's in-service limiting "stuff", we see the R1 5-year revisit of no added value. This is in contrast to the value of R2's invoking the correct triggering mechanism for events that would precipitate rechecking such protective systems and setting's coordination. AECI simply believes R1 to be overly prescriptive and its existence, as currently drafted, will destine it for future removal. **The GVSDT appreciates your position but since a large majority of stakeholders has approved the**

Organization	Question 3 Comment
	standard as it is currently written the GVSDT chooses not to modify the wording at this time. At a time when the standard is reviewed by NERC staff, the change into another format would be considered.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Pepco Holdings Inc and Affiliates	Attachment 1 and Attachment 2 have been revised since the last draft. In these latest set of attachments, although the Zone 2 loss of field characteristic has been set to operate prior to the Steady State Stability Limit (SSSL) is reached, it is also set so that it would operate prior to the generator capability curve being exceeded. This appears to be in conflict with the intent of the standard to ensure that protection should not operate before the equipment capability is exceeded. The Zone 2 characteristic should properly be set between the Generator Capability Curve and the Steady State Stability Limit. As such, Figures A.6 and A.7 in IEEE C37.102-2006 might be better coordination examples to use for these attachments.
Response: The GVSDT thanks you for your comment. The examples for illustrating coordination between AVR limiters and protection examples in the Annex of IEEE C37.102 are very similar to the one in Section G of PRC-019. The drafting team appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the P-Q or R-X diagrams.	
Cowlitz PUD	Cowlitz supports the review performed by the NAGF SRT with modification: 1. Requirement R1 appears to have been written with ever-evolving T&D systems with multiple owners/planners in play where Protection System settings may require adjustment to assure proper operation. However, this is not the case for generation facilities which remain relatively static under single management until system improvements are made. Further, it is unprecedented to require a scheduled reassessment of system control settings without cause. The Standard Requirement R1 appears to assume it necessary to review past coordination engineering work and resulting system control and Protection System settings for errors every five calendar years. We see no reliability return in such activity. Requirement R1 must be centered on first establishing that proper coordination engineering and resulting system control and Protection System settings have been completed, and documentation of such work is

Organization	Question 3 Comment
	retained in a Generation Facility Control and Protection Manual. Requirement R2 then covers the cause for review - system improvements, equipment upgrades, new operation theory, etc. - that triggers a reassessment of the coordination engineering and if necessary a revision to the Generation Facility Control and Protection Manual. The only possible item that may merit a scheduled activity is to verify all settings have not inadvertently changed, and are in compliance with the current Generation Facility Control and Protection Manual. **Once the initial study has been completed, the entity is not required to perform a full study at the 5 year time frame. The only item that may have changed in the 5 year time period is the transmission system equivalent which would affect under-excitation limiters, loss of field relay, and steady state stability limit coordination.** 2. The nonexclusive nature of the listing in section G is a concern regarding proof ofcompliance. That is, it would be burdensome to have to document a rationale for all relaysand excitation system and voltage regulator functions for which a PRC-019-1 study is felt tonot be required. The sect. G list should be complete and exclusive. **The examples were offered as such: these are examples. The GVSDT understands that the different regions and different entities will have their specific protocols for the requirements associated with NERC Standards. As such, these methods and examples are just to illustrate the flow of information, as the GVSDT perceives it. These methods and examples are not part of the Requirements, but listed in the Measures. Once again, the methods listed in the Measures are for reference, but are not intended to be an exhaustive and comprehensive list of the possible ways in which this could be implemented.** 3. The term “black start unit material” in applicability para. 4.2.4 (p.2) should be changed to the NERC defined term Blackstart Resource. Further, (departing from NAGF SRT Comments with suggested SDT response) it must be understood that Blackstart Resources must involve coordination between the TOP and the GOP. The TOP is not allowed to unilaterally designate blackstart capable resources within their restoration plan. EOP-005-2 mandates this via Requirement R13. **The wording in Part 4.2.4 comes directly from the NERC Statement of Compliance Registry**

Organization	Question 3 Comment
	Criteria. The GVSDT feels it is best to retain the NERC wording without modification.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)	Ingleside Cogeneration LP agrees that the proper coordination between a generator's voltage limiters, protective relay settings, and its stability limits can best assure its availability in response to transient conditions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed:1) All requirements for recurring assessments (R1) must contain language that focuses on the strength of the validation process - not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed - even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation.2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects.
Response: The GVSDT thanks you for your comment. Your issues relate to the "Find, Fix and Track" process that was most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states:"Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that *identifies, assesses, and corrects deficiencies*, one or more documented cyber security policies that collectively address the following topics, and review and obtain	

Organization	Question 3 Comment
CIP Senior Manager approval for those policies at least once every 15 calendar months:" This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of PRC-019 are to verify coordination of protection systems. Under this standard, the responsible entity either performed the verification or they didn't. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.	
JEA	JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Response: The GVSDT thanks you for your comment. The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not make substantive changes at this time.	
Luminant	Luminant recommends that Requirement R1 and Measure M1 be revised to clarify that the coordination described in the text is not between the Generator Operator and Transmission Operator. R1 would be revised in the following manner, "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service 1imiters and protection functions) with its applicable equipment capabilities and settings of the applicable Protection System devices and functions. 1.1. Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility". Measure M1 would be altered in the same manner.
Response: The GVSDT thanks you for your comment. The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the wording at this time.	
seattle city light	New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for

Organization	Question 3 Comment
	objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Response: The GVSDT thanks you for your comment. The GVSDT considered that entities would want to verify the said coordination of R1 prior to performing the verification of MOD-025, thus the 5 year interval was chosen. The GVSDT chooses not to modify the interval at this time.	
Southern Company	Please consider placing the applicable unit size for PRC-019 and MOD-025 equivalent to that specified by MOD-026 and MOD-027. T**he GVSDT believes that using the Compliance Registry criteria is prudent for setting the applicability of this standard. The commenter did not provide a technical justification for a non-standard Applicability.** The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. **The GVSDT believes the five year interval will not present an undue hardship on Generator Owners considering the phased implementation plan. We are not aware of any generators that run continuously for more than five years.** We suggest striking “Convertor Overtemperature” from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. **The GVSDT agrees that "Converter Overtemperature" is not a coordinatable element and has removed it from the example of Section G.** R2 specifies “perform the coordination” while M2 states “coordination review” - we believe that R2 should be changed to “review the coordination”R1 appears to have been written with evolving T&D systems in mind. It should be made clear that all that is required for a generation unit that has experienced no changes affecting the response in question is a review of the equipment state every 6 (six) years rather than requiring a new coordination study. **While the generator limiter and protection settings may not have changed, the equivalent system impedance may easily change which affects the SSSL.**

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comments. Please see specific responses above.	
Manitoba Hydro	R1 - Manitoba Hydro finds the wording ‘At a maximum of every five calendar years’ awkward. We suggest changing the wording to read ‘at least once every five calendar years’.R1.1.2 - Manitoba Hydro suggests deleting R1.1.2 which reads, “The applicable in-service Protection System devices are set to operate, isolate or de-energize equipment, in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits”. Since these are fundamental functions of any protection system device, there is no need to include this in the NERC standard. R1.1.1 - Is AVR defined somewhere? We could not find its definition in the Glossary. **The GVSDT has replaced the term “AVR” with “automatic voltage regulator”.** General Comments - 1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?. **The GVSDT believes the phased implementation program allows Generator Owners to coordinate any settings changes to limiters or protection systems with planned generator outage activities. No changes made.** 2. The concept of equivalent unit testing should be applied to both synchronous condensers and generators. Equivalent units are addressed in Row 5 of MOD-027-1 Attachment 1, but it is not clear if this attachment applies to PRC-019. We would suggest that “Attachment 1” from MOD-027-1 be added to all of the standards included in this project.3. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled “Consideration for early Compliance” with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1). **There are no "equivalent unit" criteria for this standard and the wording used in MOD-027-1 Attachment 1 does not apply to this standard.**
Response: The GVSDT thanks you for your comments. Please see specific responses above.	
PPL Corporation NERC	R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear

Organization	Question 3 Comment
Registered Affiliates	that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1 (i.e. there is not a relay that stands behind every limiter). **The GVSDT agrees that there may not be a Protective Relay behind every Limiter, and Section G is for "Example" only. The GVSDT believes that the Generator Owner is responsible for, and should posses the calculations to perform (or review) the coordination outlined by this standard.** Section 1.1.2 should be struck - as this is covered under the direction of other standards such as EOP-003. **The GVSDT disagrees that EOP-003 (Load Shedding Plans) cover coordination of generator voltage regulator limiters, protection and generator capabilities. No change made.** The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. This is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. **The GVSDT cannot possible anticipate all existing and present protective functions that Generator Owners may apply to their equipment. No change made.** The term “blackstart unit material” in applicability para. 4.2.4 (p.2) is not understood. We suggest that the SDT remove the term “blackstart unit material” or clarify when a blackstart unit designated as part of the Transmission Operator’s restoration plan would be immaterial. **The wording in the Applicability section is directly from NERC’s Statement of Registry Criteria. No change made.** Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in a Generator’s possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable. **Once the calculations are set up (in a spreadsheet, for example) reviewing, or recalculating with a new parameter, does not require significant effort. No change made.** PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. **Inadvertent tripping of any applicable generator could affect BES reliability. No change made.**

Organization	Question 3 Comment
Response: Thank you for your comments. See responses to specific comments above.	
Bonneville Power Administration	Regarding the "Functional Entities" listed in the Applicability Section, it is not clear how PRC-019 can only apply to TOs that own synchronous condensers because R1 & R2 require GOs to communicate with TOs regarding the generation equipment subject to the standard (units over 20 MVA, units connected at a common bus with total generation over 75 MVA, and blackstart units in the TOPs restoration plan). **The Applicability of TO's is only to those who own synchronous condensers because they have to evaluate the coordination of the protection on this equipment. No change made.** Regarding the "Facilities" listed in the Applicability section, BPA believes that Section 4.2.4 should apply to blackstart units designated as part of a TOP's restoration plan. The phrase "material to and designated as part of" the restoration plan creates ambiguity and would seem to require TOPs & GOs to agree on which generators are "material to" the blackstart plan. **The wording in the Applicability section is directly from NERC's Statement of Registry Criteria. No change made.** R2 is designated as a Long-Term Planning standard, but appears to allow coordination within 90 days following the implementation of setting changes. The phrase "Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1," is not clear. R1 requires coordination at least once every five years. R2 should require coordination before implementation of system, equipment, or setting changes, not within 90 days after. **The intent of the 90 days is to allow the coordination to be evaluated following discovery of a change in limiter or protection settings. The GVSDT anticipates that normally, the evaluation would occur prior to the change. No change made.**
Response: The GVSDT thanks you for your comment. See responses to specific comments above.	
Exelon Corporation and its affiliates	Section D, "Compliance," Part 1.2, "Evidence Retention," (page 4 of 11) first paragraph is unnecessary and redundant since the retention periods specified are for a six year time period which would be the maximum time between compliance audits for a registered entity. Exelon suggests that this paragraph be deleted in its entirety.

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comment. The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the wording at this time.	
SMUD	SMUD strongly suggests the SDT align the proposed PRC standard with NERC's current direction of migrating reliability standards to a Results Based Standards (RBS) and internal controls approach. This standard, along with all the other recent NERC PRC proposed standards, are vastly increasing the administrative effort by asking for more documentation of relay settings. For instance, in R1.1.2 - Is it really necessary to have a regulatory requirement for the GO to protect his own generator from damage? (Intentional Space.....)As an alternate approach, why not state that anytime a generator trips off by a protective function that must be set to coordinate with a limiter, the GO must demonstrate that the relay was set per this standard. That is, that the protective function did(emphasis added) coordinate with the limiters. If it is set correctly, there is no violation. If not, violation. This reduces the compliance burden significantly, but does not weaken the incentive to comply. Entities will want to ensure they set their relays per the standard because no one wants to cause an outage or get a violation. But no entity needs to spend time on pre-event, zero-defect, compliance documentation for all its units - only post event documentation is necessary for units that tripped. We feel this type of results based approach is a better choice for this standard.
Response: The GVSDT thanks you for your comment. Future revisions of the standard may be rewritten as RBS. The intent of the standard is to prevent inadvertent tripping due to miscoordination of limiters and protection. The GVSDT agrees that the owner would logically want to protect his own equipment, but this could lead to overprotection.	
Northeast Power Coordinating Council	Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comment. The Effective Date section refers to percentage of "applicable Facilities". Since "Facility" is a defined term, and MVA is not included in the definition, the GVSDT believes the intent is clear. The GVSDT	

Organization	Question 3 Comment
would prefer to move this standard to recirculation ballot so that the reliability benefits of the standard are achieved sooner rather than make a substantive change that would require another successive ballot.	
New York Power Authority	This Standard does not bring added reliability for the Bulk Electric System; it only adds an administrative burden for the entities. NYPA in its current protection system relay settings process inherently takes into account a margin for a unit's in-service limiters as well as other typical performance parameters.
Response: The GVSDT thanks you for your comment. The GVSDT is operating under the belief that by approving the SAR for this project, industry feels there is a reliability need.	
Utility Services	Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comment. The Effective Date section refers to percentage of "applicable Facilities". Since "Facility" is a defined term, and MVA is not included in the definition, the GVSDT believes the intent is clear. The GVSDT would prefer to move this standard to recirculation ballot so that the reliability benefits of the standard are achieved sooner rather than make a substantive change that would require another successive ballot.	
PSEG	We voted "Negative" on this standard the reasons shown below:This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1.1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a "team" with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as "applicable facilities," while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments:"The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree)

Organization	Question 3 Comment
	states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.”The SDT responded as follows:”The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.”In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses:MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.”PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.”We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon.2.No reliability benefit has been demonstrated for having the coordination review required by R1 done every five years. We suggest that the R1 be modified so that it’s clear that the entities must “verify” coordination upon the effective date ONLY, but not every 5 years thereafter. The effective date Section 5, part 5.1.1 states “By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.” Therefore, we suggest that R1 be rewritten as follows:”BY ITS EFFECTIVE DATE IN SECTION 5, each Generator Owner and Transmission Owner with applicable Facilities shall VERIFY the COORDINATION OF the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions.”

Response: The GVSDT thanks you for your comment. The verification of coordination required by this standard is closely tied to

Organization	Question 3 Comment
MOD-025 because the reactive capability verification is when miscoordination is more likely to manifest itself. MOD-026, and the other standards in the GV project are not directly linked to PRC-019 and thus have different Applicability and Implementation requirements. The requirement for a five year review is to verify that the limiter settings, protection settings, and machine capabilities have not changed since the last coordination study. If these have not changed, then the study is still valid and documentation that the settings and capabilities have not changed is sufficient.	
Southwest Power Pool Reliability Standards Development Team	We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Response: The GVSDT thanks you for your comment. There is no communication requirement in R2. Presumably, for a planned change, the owner would review the coordination prior to implementing the change. The GVSDT does not feel the present wording creates a reliability gap.	
Omaha Public Power District	We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Response: The GVSDT thanks you for your comment. There is no communication requirement in R2. Presumably, for a planned change, the owner would review the coordination prior to implementing the change. The GVSDT does not feel the present wording creates a reliability gap.	

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on August 18, 2007.
5. Draft 1 MOD-026-1 was posted for a 45-day comment period from February 17 – April 2, 2009.
6. Draft 2 MOD-026-1 was posted for a 45-day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of MOD-026-1 was posted for a 30-day concurrent comment and successive ballot period from February 29 – March 29, 2012.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This fourth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop fourth version of draft standard.	April– July 2012
2. Post response to comments and fourth version draft revision of standard for 30-day comment and successive ballot period.	October – November 2012
3. Develop responses to successive ballot comments.	December 2012 - January 2013
4. Post response to comments and conduct recirculation ballot.	February 2013
5. BOT adoption.	March 2012
7. File with regulatory authorities.	April 2013

A. **Introduction**

1. **Title:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the generator excitation control system or plant volt/var control function[1] model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities:

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an "applicable unit" that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

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[1] Excitation control system or plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.

b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 For all Interconnections:

- A technically justified[2] unit that meets NERC registry criteria and is requested by the Transmission Planner.

5. Effective Date:

5.1. For Requirements R1, and R3 through R6, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity’s applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity’s applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity’s applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

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[2] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

B. Requirements

R1. Each Transmission Planner shall provide one or more of the following to its requesting Generator Owner within 90 calendar days of receiving a written request : *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of excitation control system or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic excitation control system or plant volt/var control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific excitation control system or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit less than 20 MVA (gross nameplate rating) may be performed using either individual unit or plant aggregate model(s), or both. Each verification shall include the following:

2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,

2.1.2. Manufacturer, model number (if available), and type of excitation control system or plant volt/var control function installed including, but not limited to static, AC brushless, DC rotating, and volt/var function,

2.1.3. Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator,

2.1.4. Model structure and data for the excitation control system, including the closed loop voltage regulator if a closed loop voltage regulator is installed or the model structure and data for the plant volt/var control function system,

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used, and

2.1.6. Model structure and data for power system stabilizer, if so equipped.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit:

- Written notification from its Transmission Planner (in accordance with Requirement R6) that the excitation control system or plant volt/var control function model is not usable,
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system or plant volt/var control function model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated excitation control system or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[3] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[3] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the excitation control system or plant volt/var control function that alter the equipment response[4] characteristic.[5] *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Generator Owner shall provide a written response to its Transmission Planner, within 90 calendar days following receipt of a technically justified[6] unit request from the Transmission Planner to perform a model review of a unit or plant that includes one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Details of plans to verify the model (in accordance with Requirement R2), or

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[3] If verification is performed, the 10-year period as outlined in MOD-026 Attachment 1 is reset.

[4] Ibid.

[5] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

[6] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.

R6. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 6.1 through 6.3) or is not usable, and shall include a technical description if the model is not usable that includes the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

6.1. The excitation control system or plant volt/var control function model initializes to compute modeling data without error,

6.2. A no-disturbance simulation results in negligible transients, and

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator excitation control system or plant volt/var control function model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 180 calendar days of making changes.

M5. Evidence for Requirement R5 must include the Generator Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 90 calendar days following receipt of a technically justified request.

M6. Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for three calendar years from the date the document was provided.
- The Generator Owner shall retain the latest excitation control system or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner after the timeframe specified in MOD-026 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner verified models that omitted one of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted two of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) but omitted four or more of the six parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice. OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.
R5	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner failed to provide a written response to the Transmission Planner within 180 calendar days following receipt of a technically justified request to perform a model review of an applicable unit. OR The Generator Owner’s written response failed to include one of the sub bullets of Requirement R5

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for all specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, “Model Validation for Wind Turbine Generator Models”, IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, “Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, “Dynamic Modeling of GE Wind Plants for Stability Simulations,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, “Description and Technical Specifications for Generic WTG Models – A Status Report,” Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ

9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, “Modeling of GE Wind Turbine-Generators for Grid Studies,” version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, “Field Testing & Model Validation of Wind Plants,” in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, “Experience with Field and Factory Testing for Model Validation of GE Wind Plants,” in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belgium, March/April 2008
13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
14. W.W. Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
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MOD-026 Attachment 1

Excitation Control System or Plant Volt/Var Function Model Verification Periodicity

Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 10-year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-026 Attachment 1

Excitation Control System or Plant Volt/Var Function Model Verification Periodicity

Row Number	Verification Condition	Required Action
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
5	The Generator Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-026 Attachment 1

Excitation Control System or Plant Volt/Var Function Model Verification Periodicity

Row Number	Verification Condition	Required Action
6	New or existing applicable unit does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).
7	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10-year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Establishing the recurring 10-year unit verification period start date:

The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 2: Consideration for early compliance:

Existing generator excitation control system or plant volt/var control function model verification is sufficient for demonstrating compliance for a 10-year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted~~.~~ (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on ~~(~~August 18, 2007~~).~~ .
5. Draft 1 MOD-026-1 was posted for a 45-day comment period from February 17 – April 2, 2009.
6. Draft 2 MOD-026-1 was posted for a 45-day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of MOD-026-1 was posted for a 30-day concurrent comment and successive ballot period from February 29 – March 29, 2012.

Proposed Action Plan and Description of Current Draft:

This is the ~~third~~fourth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This ~~second~~fourth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop ~~third~~fourth version of draft standard.	~~August 2011 – February~~April– July~~ne~~ 2012
2. Post response to comments and ~~third~~fourth version draft revision of standard for 30-day comment and successive ballot period.	~~February – March~~October – November 2012
3. Develop responses to successive ballot comments.	~~April – May~~December 2012 - January 201~~2~~3
4. Post response to comments and conduct recirculation ballot.	~~June~~February -201~~2~~3
~~5. Conduct recirculation ballot.~~	~~June2012October 2012~~
~~7~~5~~6~~. BOT adoption.	~~July~~March 201~~2~~2
~~8~~7. File with regulatory authorities.	April 2013~~September~~

	~~2012~~

A. **Introduction**

1. **Title:** Verification of Models and Data for Generator Excitation Control System ~~and~~or Plant Volt/Var Control Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the generator excitation control system ~~and~~or plant volt/var control~~[1]~~ function[2] model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system ~~and~~or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities:

For the purpose of ~~this standard,~~ the ~~following~~requirements contained herein, Facilities that are ~~considered,~~ directly connected to the Bulk Electric System (BES) will be collectively referred as an "applicable ~~units[3].~~"

~~Units or plants with an average capacity factor[4] greater than 5 percent over the most recent three calendar years, beginning on January 1 and ending on December 31,~~unit" that meet the following:

~~[1] Excitation control system and plant volt/var control function:~~

~~a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.~~

~~b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.~~

[2] Excitation control system or plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.

b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

~~[3] Applicable generating units do not include startup or standby units not normally connected to the grid.~~

~~[4] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.~~

4.2.1 ~~Generating units connected to~~Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating~~) directly connected to the bulk power system.~~).

~~**4.2.1.2** For each~~Individual generating plant ~~/ Facility~~ consisting of ~~one or more~~ multiple generating units that are directly connected ~~to the bulk power system~~ at a common BES bus with total generation greater than 100 MVA (gross aggregate ~~rating):~~

~~**4.2.1.3**~~**4.2.1.2** ~~Each individual generating unit greater than 20 MVA (gross~~ nameplate rating~~); and~~).

- ~~Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

4.2.2 ~~Generating units connected to~~Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating~~) directly connected to the bulk power system.~~).

~~**4.2.2.2** For each~~Individual generating plant ~~/ Facility~~ consisting of ~~one or more~~ multiple generating units that are directly connected ~~to the bulk power system~~ at a common BES bus with total generation greater than 75 MVA (gross aggregate ~~rating):~~

~~**4.2.2.3**~~**4.2.2.2** ~~Each individual generating unit greater than 20 MVA (gross~~ nameplate rating~~); and~~).

- ~~Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

4.2.3 ~~Generating units connected to~~Generation in the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating~~) directly connected to the bulk power system.~~).

4.2.3.2 ~~For each~~Individual generating plant ~~/ Facility~~ consisting of ~~one or more~~multiple generating units that are directly connected ~~to the bulk power system~~ at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating~~):~~).

- ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~
- ~~Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

4.2.4 For all Interconnections:

- ~~Any registered~~A technically justified[5] unit that meets NERC registry criteria and is requested by the ~~Planning Coordinator~~Transmission Planner.

5. Effective Date:

~~**5.1.** In those jurisdictions where regulatory approval is required:~~

~~**5.1.1** Each responsible entity shall ensure compliance with~~For Requirements R1, and R3 through R6 ~~by~~, the first day of the first calendar quarter~~, four years following~~ beyond the date that this standard is approved by applicable regulatory ~~approval.~~

5.1. ~~Each Generator Owner shall ensure at least 30 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of~~authorities. In those jurisdictions where regulatory approval is not required, the ~~first calendar quarter,~~standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

~~**5.1.2**~~ For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval~~.~~

~~**5.1.3** Each Generator Owner shall ensure at least 50 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval:~~

5.2. ~~Each Generator Owner shall ensure 100 percent of its applicable units are compliant with Requirement R2 by~~, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter~~, ten~~ that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable ~~regulatory approval:~~to such ERO governmental authorities.

~~**5.3.** In~~For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required~~:~~

~~**5.3.1** Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter, four years following Board of Trustees adoption.~~

~~**5.4.**~~**5.3.** ~~Each Generator Owner shall ensure at least 30 percent of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2~~

[5] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

~~by~~, on the first day of the first calendar quarter~~, four~~ thirty that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

~~5.4.1 Each Generator Owner shall ensure at least 50~~For Requirement R2, 100 percent of ~~its~~the entity's applicable ~~units per Interconnection on an MVA basis are compliant with Requirement R2 by~~unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter~~, six~~ that is 10 years following NERC Board of Trustees adoption~~.~~

~~5.5.~~5.4. ~~Each Generator Owner shall ensure 100 percent of its applicable units are compliant with Requirement R2 by the first day of the first calendar quarter, ten years following Board of Trustees adoption~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide one or more of the following ~~instructions and model data~~ to its requesting Generator Owner within 90 calendar days of receiving a written request ~~for those instructions or model data:~~: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning~~]~~:]*

- Instructions on how to obtain the list of excitation control system ~~and~~or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation~~.~~,
- Instructions on how to obtain the ~~Transmission Planner's software manufacturer's~~ dynamic excitation control system ~~and~~or plant volt/var control function model library block diagrams and/or data sheets~~.~~ for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit ~~or plant~~ specific excitation control system ~~and~~or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide~~,~~ for each ~~of its~~ applicable unit~~s~~, a verified generator excitation control system ~~and~~or plant volt/var control function model, including documentation and data (as specified in Part~~s~~ 2.1~~ and 2.2~~) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1~~, to ensure modeling data is accurate for use in simulation software.~~. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. ~~Perform verifications~~Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner~~ that~~. Verification of an individual unit less than 20 MVA (gross nameplate rating) may be performed using either individual unit or plant aggregate model(s), or both. Each verification shall include~~(s)~~ the following ~~information~~:

2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion ~~at the applicable unit's point of interconnection~~ from either a staged test or a measured system disturbance~~.~~,

2.1.2. Manufacturer, model number (if available), and type of excitation control system ~~and~~or plant volt/var control function installed ~~(such as~~including, but not limited to static, AC brushless, DC rotating, and volt/var function~~).~~,

2.1.3. Model structure and data ~~(such as~~including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data~~)~~ for the generator~~ (or plant equivalent).~~,

2.1.4. Model structure and data for the excitation control system, ~~for the plant volt/var function, and for~~including the closed loop voltage regulator if ~~the~~a closed loop voltage regulator is installed~~.~~ or the model structure and data for the plant volt/var control function system,

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used~~.~~, and

2.1.6. Model structure and data for power system stabilizer, if so equipped.

~~**2.2.** For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6~~

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items~~. The written response shall contain either the technical basis for maintaining the current model, or the model changes, or a plan to perform model verification[6] (in accordance with Requirement R2)~~ ~~*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*:~~ for an applicable unit:

- Written notification from its Transmission Planner (in accordance with Requirement R6) that the excitation control system ~~and~~or plant volt/var control function model is not ~~"~~usable~~," or~~,
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system ~~and~~or plant volt/var control function model, or

[6] ~~If verification is performed, the 10 year period as outlined in Attachment 1 is reset.~~

- Written comments and supporting evidence from its Transmission Planner indicating that the ~~predicted~~simulated excitation control system ~~and~~or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[7] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[7] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the excitation control system ~~and~~or plant volt/var control function that alter the equipment response[8] characteristic.[9] *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Generator Owner shall provide a written response to its ~~Planning Coordinator~~Transmission Planner, within 90 calendar days following receipt of a technically justified[10] unit request from the ~~Planning Coordinator~~Transmission Planner to perform a model review of ~~any~~a unit~~/~~ or plant ~~not included in the Applicability~~ that includes one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning~~]:~~]*

- Details of plans to verify the model (in accordance with Requirement R2~~)~~), or
- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on ~~a walk down~~an on-site review of the equipment.

R6. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system ~~and~~or plant volt/var control function model information ~~whether~~in accordance with Requirement R2 that the model is us~~e~~able (meets the criteria specified in Parts 6.1 through 6.3~~),~~) or is not us~~e~~able~~;~~, and

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[7] If verification is performed, the 10-year period as outlined in MOD-026 Attachment 1 is reset.

[8] ~~Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change.~~[8] Ibid.

[9] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

[10] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

shall include a technical description if the model is not ~~useable. .~~usable that includes the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

6.1. The excitation control system ~~and~~or plant volt/var control function model initializes to compute modeling data without error~~.~~,

6.2. A no-disturbance simulation results in negligible transients~~.~~, and

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

C. Measures

M1. ~~Evidence for Requirement R1~~The Transmission Planner must ~~include~~have and provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of ~~transmission of requested instructions and data, such as dated~~a written transmittal (e.g., electronic mail ~~messages, dated~~ message, postal ~~receipts, dated~~ receipt, or confirmation of facsimile ~~transmission~~) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. ~~Evidence for Requirement R2 must include, for each of the Generator Owner's applicable Facilities, the verification report showing that the~~ The Generator Owner must have and provide dated evidence it verified each generator excitation control system ~~and~~or plant volt/var control function model ~~was verified~~ according to Part 2.1 for each applicable unit and ~~dated evidence of transmission, such as~~ a dated transmittal (e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmission~~) as ~~specified~~evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal~~, such as a dated~~ (e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmission~~) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's ~~Facilities~~applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or ~~dated~~ plans to perform a model verification and dated evidence ~~of transmittal, such as dated~~(e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmittal~~) it provided the revised model and data or plans within 180 calendar days of making changes.

M5. Evidence for Requirement R5 must include~~, for each request received as specified in Requirement R5, the~~ the Generator Owner's dated written response ~~provided~~ containing the information identified in Requirement R5 and dated evidence ~~of transmittal, such as dated~~(e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmittal~~) it provided a written response within 90 calendar days following receipt of a technically justified request.

M6. Evidence of Requirement R6 must include, for each model received, the dated response ~~containing the information required in~~ indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal~~, such as dated~~ (e.g., electronic mail ~~messages, dated~~message, postal receipt~~s~~, or ~~dated~~ confirmation of facsimile ~~transmittal~~) that the Generator Owner was notified within 90 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity~~

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for ~~3~~three calendar years from the date the document was provided.
- The Generator Owner shall retain the latest ~~and previous~~ excitation control system ~~and~~or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for ~~3~~three calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but ~~no more~~less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but ~~no more~~less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but ~~no more~~less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within ~~181~~180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s~~)~~), including documentation and data to its Transmission Planner after the timeframe specified in MOD-026 Attachment 1 but ~~no more~~less than ~~30~~or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner verified models that omitted one of the six Parts identified in Requirement R2, ~~Subp~~Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s~~)~~), including documentation and data to its Transmission Planner more than ~~30~~90 calendar days but ~~no more~~less than ~~60~~or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted two of the six Parts identified in Requirement R2, ~~Subp~~Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s~~)~~), including documentation and data to its Transmission Planner more than ~~60~~180 calendar days but ~~no more~~less than ~~90~~or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the six Parts identified in Requirement R2, ~~Subp~~Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified ~~generator excitation control system~~model(s), including documentation and ~~plant volt/var control function model~~data more than ~~90~~270 calendar days late ~~or failed to provide the verified model(s)~~ to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, ~~Subp~~Part 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) ~~that~~but omitted four or more of the six ~~P~~parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but ~~no more~~less than or equal to 120 calendar days of receiving written notice. ~~(R3)~~	The Generator Owner provided a written response more than 120 calendar days but ~~no more~~less than or equal to 150 calendar days of receiving written notice. ~~(R3)~~	The Generator Owner provided a written response more than 150 calendar days but ~~no more~~less than or equal to 180 calendar days of receiving written notice. ~~(R3)~~	The Generator Owner failed to provide a written response within ~~181~~180 calendar days of receiving written notice ~~(R3).~~. OR ~~The Generator Owner's written response was provided within 181 calendar days of receiving written notice however, the~~The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but ~~no more~~less than or equal to 210 calendar days of making changes to the excitation control system ~~and~~or plant volt/var control function that altered the equipment response characteristic. ~~(R4)~~	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but ~~no more~~less than or equal to 240 calendar days of making changes to the excitation control system ~~and~~or plant volt/var control function that altered the equipment response characteristic. ~~(R4)~~	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but ~~no more~~less than or equal to 270 calendar days of making changes to the excitation control system ~~and~~or plant volt/var control function that altered the equipment response characteristic. ~~(R4)~~	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within ~~271~~270 calendar days of making changes to the excitation control system ~~and~~or plant volt/var control function that altered the equipment response characteristic ~~(R4).~~.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The Generator Owner provided a written response more than 90 calendar days but ~~no more~~less than or equal to 120 calendar days to the ~~Planning Coordinator~~Transmission Planner following receipt of a technically justified request to perform a model review of ~~a~~an applicable unit~~/plant. (R5)~~.	The Generator Owner provided a written response more than 120 calendar days but ~~no more~~less than or equal to 150 calendar days to the ~~Planning Coordinator~~Transmission Planner following receipt of a technically justified request to perform a model review of ~~a~~an applicable unit~~/plant. (R5)~~.	The Generator Owner provided a written response more than 150 calendar days but ~~no more~~less than or equal to 180 calendar days to the ~~Planning Coordinator~~Transmission Planner following receipt of a technically justified request to perform a model review of ~~a~~an applicable unit~~/plant. (R5)~~. ~~OR~~ ~~The Generator Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the written response failed to include Requirement R5, Subpart 5.2 or Part 5.3.~~	The Generator Owner failed to provide a written response to the ~~Planning Coordinator~~ Transmission Planner within 180 calendar days following receipt of a technically justified request to perform a model review of ~~a~~an applicable unit~~/plant (R5)~~.. OR The Generator ~~Owner provided a written response within 181 calendar days to the Planning Coordinator following receipt of a technically justified request to perform a model review of a unit/plant however the~~Owner's written response failed to include one of the sub bullets of Requirement R5~~, Subparts 5.2 and 5.3.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information. ~~(R6)~~	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information. ~~(R6)~~ OR The Transmission ~~Planner provided a written response within 181 calendar days to the Generator Owner however the~~Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R6, ~~Subp~~Parts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is useable or not useable; including a technical description if the model is not useable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information. ~~(R6)~~ OR The Transmission ~~Planner provided a written response within 181 calendar days to the Generator Owner however the~~Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R6, ~~Subp~~Parts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within ~~181~~180 calendar days of receiving the verified model information~~(R6).~~. OR The Transmission ~~Planner provided a written response within 181 calendar days to the Generator Owner however the~~Planner's written response omitted confirmation for all specified model criteria listed in Requirement R6, ~~Subp~~Parts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, "Model Validation for Wind Turbine Generator Models", IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, "Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies," IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, "Dynamic Modeling of GE Wind Plants for Stability Simulations," IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, "Description and Technical Specifications for Generic WTG Models – A Status Report," Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ

9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, “Modeling of GE Wind Turbine-Generators for Grid Studies,” version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, “Field Testing & Model Validation of Wind Plants,” in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, “Experience with Field and Factory Testing for Model Validation of GE Wind Plants,” in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belg~~u~~ium, March/April 2008
13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
14. W.W. Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, “Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations,” Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003
17. P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

~~MOD-026 Attachment 1~~

~~Excitation Control System and Plant Volt/Var Function Model Verification Periodicity~~

~~Periodicity Determination Supporting Criteria~~MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 10-year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

~~Periodicity Determination Supporting Criteria~~MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
5	The Generator Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

~~Periodicity Determination Supporting Criteria~~MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
6	New or existing applicable unit does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).
7	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10-year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

~~Periodicity Determination Supporting Criteria~~MOD-026 Attachment 1

Excitation Control System or Plant Volt/Var Function Model Verification Periodicity

Row Number	Verification Condition	Required Action

~~Criteria~~NOTES:

NOTE **1**: Establishing the ~~**Initial Ten Year Unit Verification Period Start Date:**~~

~~**For each applicable unit, set the initial start date for compliance with Requirement R2 to the 30 percent, 50 percent, or 100 percent Standard Implementation Effective Dates established for compliance in accordance with the ten calendar**~~ recurring 10-year ~~**transition period and in accordance with the following rules:**~~

- ~~**30 percent of the applicable units in the generation fleet unit MVA is compliant within the first 4 years.**~~
- ~~**50 percent of the applicable units in the generation fleet unit MVA is compliant within the first 6 years.**~~
- ~~**100 percent of the applicable units in the generation fleet unit MVA is compliant within the first 10 years.**~~

~~**Criteria 2: Establishing the Recurring Ten Year Unit Verification Period Start Date**~~unit verification period start date:

The start date is the actual ~~**data collection**~~ date of submittal of a verified model to the Transmission Planner for the most recently performed ~~**applicable unit verification.**~~

~~**Criteria 3: For the purpose of calculating the initial ten year**~~ unit verification ~~**period 30 percent, 50 percent, or 100 percent threshold for generation fleet compliance, equivalent unit MVA is included**~~.

NOTE 2: Consideration for ~~**Early Compliance**~~early compliance:

Existing generator excitation control system ~~**and**~~or plant volt/var control function model verification is sufficient for demonstrating compliance for a ~~**ten**~~ 10-year period from the actual ~~**verification**~~transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

~~Event Triggering Verification~~	~~Verification Periodicity~~	~~Comments~~
~~Establishing the initial verification period (Criteria 1) for an applicable unit~~ ~~(Requirement R2)~~	~~Record and collect excitation control system and plant volt/var control response validation data on or before the initial start date per Criteria 1~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the response was recorded.~~ ~~Criteria 3 applies when calculating generation fleet compliance during the 10-year transition period~~
~~Subsequent verification for an existing applicable unit~~ ~~(Requirement R2)~~	~~Record and collect excitation control system and plant volt/var control function response validation data on or before the ten year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control function response used for the current validation.~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected.~~
~~Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system and plant volt/var control function equipment installed with settings final~~ ~~(Requirement R2)~~	~~Record and collect excitation control system and plant volt/var control function response validation data no more than 356 days from the commissioning date~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~Existing applicable unit that is equivalent to another operating unit(s) at the same physical location.~~ ~~AND~~ ~~Each equivalent unit has the same MVA nameplate rating.~~ ~~AND~~	~~Verify a different equivalent unit during each ten year verification period.~~ ~~.~~	~~Document circumstance with a written statement and include with the verified model and documentation and data provided to the Transmission Provider for the verified equivalent unit.~~

~~Event Triggering Verification~~	~~Verification Periodicity~~	~~Comments~~
~~The nameplate rating is ≤ 350 MVA.~~ ~~AND~~ ~~Each equivalent unit has identical applicable components and settings.~~ ~~AND~~ ~~The model for one of these equivalent units has been verified.~~ ~~(Requirement R2)~~		~~Criteria 3 applies when calculating generation fleet compliance during the 10-year transition period.~~
~~Existing unit was subjected to an activity that resulted in an alteration of the response of the excitation control system and plant volt/var control function model and the altered unit settings are final~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan.~~ ~~(Requirement R4)~~	~~Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~The Generator Owner receives written comments including dated electronic or hard copy evidence indicating that the recorded excitation control system and plant volt/var response to a transmission system event did not did not match the predicted excitation control system model response.~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan.~~ ~~(Requirement R3)~~	~~Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~The Generator Owner receives written comments detailing technical concerns with the Generator Owner's excitation control system and plant volt/var control function model verification documentation.~~	~~Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that~~

~~Event Triggering Verification~~	~~Verification Periodicity~~	~~Comments~~
~~AND~~ ~~The Generator Owner has submitted a verification plan~~ ~~(Requirement R3)~~	~~submitted verification plan.~~	~~the recorded response was collected.~~
~~The excitation control system and volt/var control model are identified as unusable by the Transmission Planner.~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan.~~ ~~(Requirement R3)~~	~~Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~Planning Coordinator requests a review of the excitation control system and plant volt/var control function model for a unit or plant that is not an applicable unit.~~ ~~AND~~ ~~The Generator Owner has submitted a verification plan.~~ ~~(Requirement R5)~~	~~Record and collect excitation control system and plant volt/var control response validation data no more than 365 calendar days from the date of the submitted verification plan.~~	~~Transmit the verified model and documentation and data to the Transmission Planner no more than 180 calendar days from the date that the recorded response was collected.~~
~~New or existing applicable unit does not include active closed loop function.~~	~~Not required until unit has an installed control system~~	~~Document circumstance with a written statement~~ ~~Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) once an active closed loop function is established.~~

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units."

Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant / Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

For all Interconnections:

- Any technically justified[1] unit that meets NERC registry criteria and is requested by the Transmission Planner.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter following applicable regulatory approval.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA are compliant with Requirement R2 By the first day of the first calendar quarter, 10 years following applicable regulatory approval.

[1] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA is compliant with Requirement R2 By the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a 10 year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the 10 year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements 10 years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Retirements

None

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System ~~Functions and~~or Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System ~~Functions and~~ or Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units~~[1]~~."

Units or plants ~~with an average capacity factor[2] greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31,~~ that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.

~~[1] Applicable generating units do not include startup or standby units not normally connected to the grid.~~
~~[2] Once a capacity factor exemption is declared by notifying the Transmission Planner, verification is not required for 10 calendar years from the date eligibility occurs. At the end of this 10 calendar year timeframe, the current average 3 year capacity factor (for years 8, 9, and 10) is examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within one year of the date the capacity factor exemption expired with the 10 calendar year periodicity requirement reset based on the verification date. For the definition of capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.~~

- ~~For e~~Each generating plant ~~/ Facility~~ consisting of ~~one or more~~multiple -units that are directly connected to the ~~bulk power system~~Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating):
  - ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~
  - ~~Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.
- ~~For e~~Each generating plant ~~/ Facility~~ consisting of multiple ~~one or more~~ units that are directly connected to the ~~bulk power system~~Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~
  - ~~Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the ~~bulk power system~~Bulk Electric System.
- ~~For e~~Each generating plant / Facility consisting of ~~one~~ multiple~~or more~~ units that are connected to the ~~bulk power system~~Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating):
  - ~~Each individual generating unit greater than 20 MVA (gross nameplate rating); and~~
  - ~~Each generating plant / Facility comprised consisting of individual generating units less than 20 MVA (gross nameplate ratings)~~

For all Interconnections:

- Any ~~registered~~ technically justified[3] unit that meets NERC registry criteria and is requested by the Transmission Planner. ~~ing Coordinator.~~

[3] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter~~, four years~~ following applicable regulatory approval.
- Each Generator Owner shall ensure at least 30 percent~~%~~ of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval.
- Each Generator Owner shall ensure at least 50 percent~~%~~ of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis~~ are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval.
- Each Generator Owner shall ensure 100 percent~~%~~ of its applicable unit~~s~~ gross MVA are compliant with Requirement R2 By the first day of the first calendar quarter, 10~~ten~~ years following applicable regulatory approval.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter~~, four years~~ following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent~~%~~ of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis are~~ is compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent~~%~~ of its applicable unit~~s~~ gross MVA per Interconnection ~~on an MVA basis are~~ is compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100 percent~~%~~ of its applicable unit~~s~~ gross MVA ~~are~~ is compliant with Requirement R2 By the first day of the first calendar quarter, 10~~ten~~ years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a 10~~ten~~ year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the 10~~ten~~ year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements ~~ten~~ 10 years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Retirements

None

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 of PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from February 29 – March 29, 2012.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This fourth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop third version draft standard.	April - July 2012
2. Post response to comments and conduct successive ballot.	October-November 2012
3. Develop responses to ballot comments.	December 2012 – January 2013
4. Post responses to comments and conduct recirculation ballot.	February 2013

5. BOT adoption.	March 2013
6. File with regulatory authorities.	April 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Performance During Frequency and Voltage Excursions

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure generating units remain connected during frequency and voltage excursions and ensure expected generating unit performance during frequency and voltage excursions is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

   5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

   5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

   5.1.5 By the first day of the first calendar quarter, six calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirement R5.

   5.2. In those jurisdictions where regulatory approval is not required:

   5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.2.5 By the first day of the first quarter, six calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirement R5.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its generating unit shall set such protective relaying so that the frequency protective relaying does not operate to trip the unit within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

- Generation may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.
- Generation may trip if clearing a system fault necessitates disconnecting the generation.
- Generation may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated equipment limitations in accordance with Requirement R3 for an existing generating unit[2].

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its generating unit shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection[3]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2 or within the voltage recovery characteristics of a location-specific Transmission Planner's study if the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2 subject to the following exceptions : *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generation may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generation may trip if clearing a system fault necessitates disconnecting a generating unit.
- Generation may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generation may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3 for an existing generating unit

R3. Each Generator Owner of an existing generating unit shall document each known equipment limitation (excluding limitations that are caused by generator frequency and voltage protective relays) that prevents a generating unit, from meeting the criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an

[2] To include generating units previously commissioned, or generating units under construction, or generating units with an executed interconnection agreement or power purchase agreement by the effective date of PRC-024-1 Requirement R5,

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

actual event, or manufacturer's advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

3.1. The Generator Owner shall communicate the documented equipment limitation, or the removal of a previously documented equipment limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the equipment limitation or when either of the following occurs:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.
- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).

R4. Each Generator Owner of an existing generating unit shall provide an estimate of the time duration the existing generating unit will remain connected (considering performance of the auxiliary systems as well as the generator) if the unit were to experience a frequency or voltage excursion. The voltage or frequency profile at the point of interconnection is determined by dynamic simulation provided by a Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit and has requested the time duration estimate. The estimate is to be provided to the requesting Reliability Coordinator, Planning Coordinator, Transmission Owner, or Transmission Planner within 60 calendar days of receipt of a written request.

If the Generator Owner expects the existing generating unit will remain connected for longer than 10 minutes, the estimate should indicate the existing unit is not expected to trip. The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment. Detailed unit performance studies are not required to develop the estimate. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R5. Each Generator Owner shall design, build, and maintain new [4] generating units and plants (including auxiliary systems) consistent with the parameters set forth in PRC-024 Attachments 1 and 2, such that the generation, when operating at or above the minimum sustainable generation threshold (and for a generating plant consisting of multiple units with total generation greater than 75 MVA gross aggregate nameplate rating, when the generating plant is producing at least 20 percent of the plant's aggregate nameplate capacity) will not trip due to a frequency excursion or voltage excursion at the point of interconnection, caused by an event on the transmission system external to the generating

[4] Excluding generators referenced in PRC-024-1 Footnote 2.

plant, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- For a new generating plant consisting of multiple units less than 20 MVA each with total plant generation greater than 75 MVA (gross aggregate nameplate rating), up to 10 percent of the individual generating units may disconnect as a result of the frequency or voltage excursion.
- If the Transmission Planner has provided the Generator Owner with location-specific voltage recovery characteristics as described in Requirement R2, Part 2.2, then the generation may operate to a less stringent voltage ride-through performance criterion than the duration curve identified in PRC-024 Attachment 2 consistent with those provided characteristics.
- Generation may trip if this action is designed as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generation may trip if clearing a system fault necessitates disconnecting the generation.
- Generation may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation. If an equipment limitation is identified following a plant trip caused by a frequency or voltage excursion, the Reliability Coordinator may grant a retroactive temporary exemption for that limitation if the Generator Owner develops and implements an acceptable plan to address the limitation.
- Generation may trip if the protective functions (such as out-of-step functions, or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

R6. Each Generator Owner shall provide its generator protection trip settings to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner (that monitors or models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless otherwise directed by the requesting Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence such as dated setting sheets, calibration sheets, or other documentation, that generator frequency protective relays have been set in accordance with Requirement R1.

M2. Each Generator Owner shall have evidence such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies, that generator voltage protective relays have been set in accordance with Requirement R2.

M3. Each Generator Owner shall have evidence that it has documented and communicated any equipment limitations (excluding limitations that are caused by generator frequency and voltage protective relays) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

M4. Each Generator Owner shall have evidence such as a copy of the estimate of time duration report and correspondence, such as dated e-mails, or other documentation that an estimate of the time duration of its existing generating unit(s) as a result of a frequency excursion or voltage excursion has been communicated in accordance with Requirement R4, and copies of any requests it has received for that information.

M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied.

M6. Each Generator Owner shall have evidence such as dated e-mails, correspondence or other evidence that it communicated generator protective relay settings to a requesting entity within 60 calendar days of a request or change in setting(s) in accordance with Requirement R6 and copies of any requests it has received for that information..

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R6, Measures M1 through M6; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit has no documented and communicated equipment limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit has no documented and communicated equipment limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 30 calendar days but less than or equal to 40 calendar days of identifying the limitation.	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 40 calendar days but less than or equal to 50 calendar days of identifying the limitation.	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 50 calendar days but less than or equal to 60 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 60 calendar days of identifying the limitation.
R4	The Generator Owner provided an estimate of a unit's performance more than 60 calendar days but less than or equal to 70 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 70 calendar days but less than or equal to 80 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 80 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner failed to provide an estimate of a unit's performance within 90 calendar days of a written request. .
R5	N/A	N/A	N/A	The Generator Owner's generator tripped due to a frequency excursion within the no-trip parameters set forth in Attachment 1 and did not meet any of the exceptions specified in the bulleted list within Requirement R5. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Generator Owner's generator tripped due to a voltage excursion within the no-trip parameters set forth in Attachment 2 and did not meet any of the exceptions specified in the bulleted list within Requirement R5.
R6	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than 60 calendar days but less than or equal to 70 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 70 calendar days of a written request.	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than 70 calendar days but less than or equal to 80 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 70 calendar days but less than or equal to 80 calendar days of a written request.	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than 80 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 80 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings as specified by Requirement R6 within 90 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 90 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

Version History

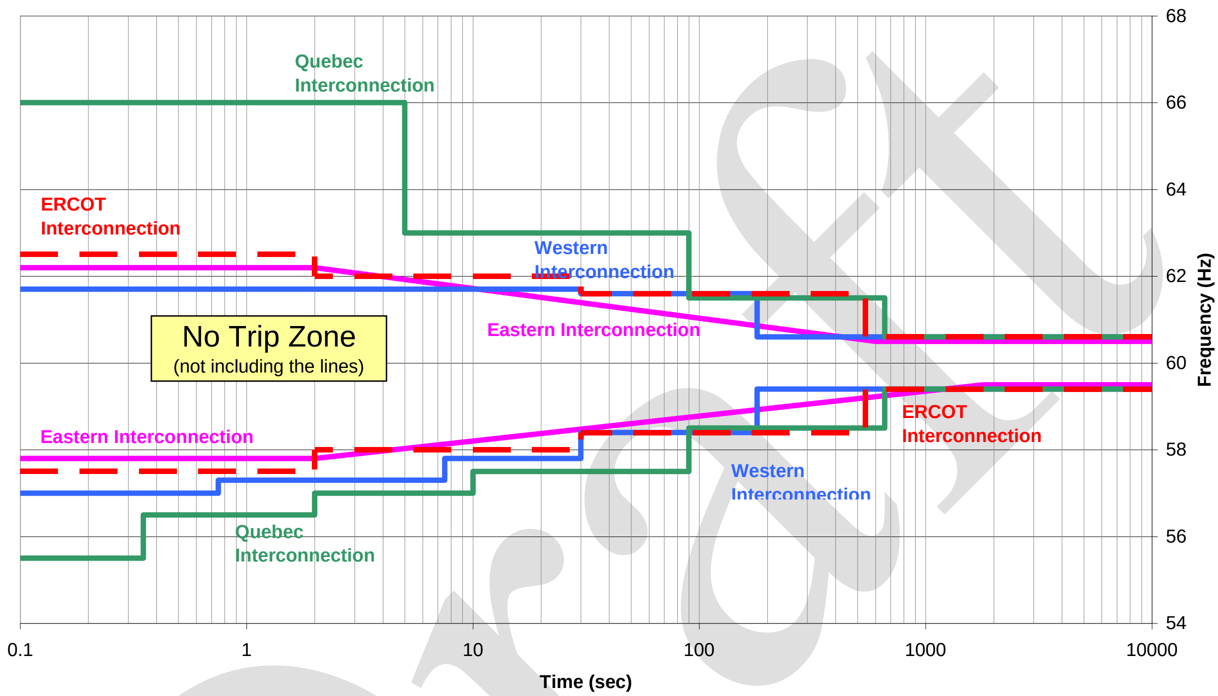
Version	Date	Action	Change Tracking

G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥62.2	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(91.1132-1.46*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

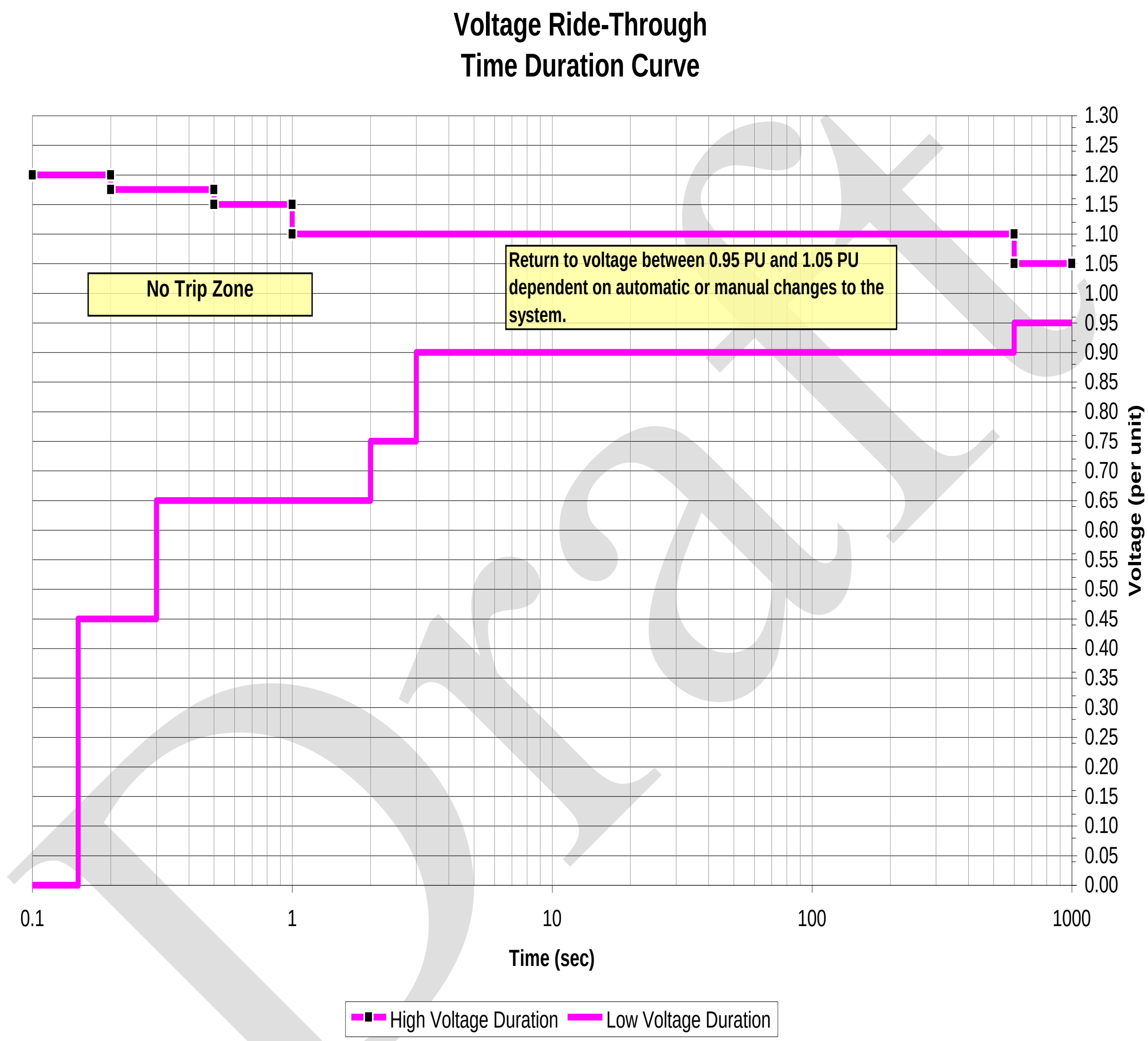
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (Sec)**
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥62.5	Instantaneous trip	≤57.5	Instantaneous trip
≥62.0	2	≤58.0	2
≥61.6	30	≤58.4	30
≥60.6	540	≤59.4	540
<60.6	Continuous operation	>59.4	Continuous operation

PRC-024— Attachment 2



Curve Data Points:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	0.00	0.15
≥1.175	0.20	<0.45	0.30
≥1.15	0.50	<0.65	2.00
≥1.10	1.00	<0.75	3.00
>1.05	600	<0.90	600
≤1.05	Continuous operation	≥0.95	Continuous operation

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

6. Use the following assumptions to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating,
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals).
7. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
8. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 of PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from February 29 – March 29, 2012.

Proposed Action Plan and Description of Current Draft:

This is the ~~third~~fourth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This ~~second~~fourth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop ~~third~~fourth version draft standard.	~~August 2011 – February~~April – July 2012
2. Post response to comments and ~~third~~fourth version draft revision of standard for 30 day comment and successive ballot period.	~~February – March~~October - November 2012
3. Develop responses to successive ballot comments.	~~April – June~~December 2012 – January 2013

4. Post response to comments and conduct recirculation ballot.	~~July~~February 201~~2~~3
~~5. Conduct recirculation ballot.~~	~~July 2012~~
~~7~~5. BOT adoption.	~~August~~March 201~~2~~3
~~8~~6. File with regulatory authorities.	~~October~~April 201~~2~~3

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Performance During Frequency and Voltage Excursions

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure generating units remain connected during frequency and voltage excursions~~,~~ and ensure expected generating unit performance during frequency and voltage excursions~~,~~ is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. ~~Each~~In those jurisdictions where regulatory approval is required:

   ~~5.1.~~5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner shall ~~verify that~~have verified at least ~~33~~40 percent of its ~~applicable units~~Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6 ~~by the first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption.~~ .

   ~~5.2.~~5.1.2 ~~Each~~By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner shall ~~verify that~~have verified at least ~~66~~60 percent of its ~~applicable units~~Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6 ~~by the first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption.~~ .

   5.1.3 ~~Each~~By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner shall ~~verify that 100~~have verified at least 80 percent of its ~~applicable units~~Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6 ~~by~~.

   5.1.4 By the first day of the first calendar quarter ~~three~~, five calendar years following applicable regulatory approval~~; or, in~~, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.1.5 By the first day of the first calendar quarter, six calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirement R5.

5.2. In those jurisdictions where ~~no~~ regulatory approval is not required~~,~~:

~~5.3.~~ By the first day of the first calendar quarter ~~three~~ , two calendar years following Board of Trustees ~~adoption.~~

5.2.1 ~~Requirement R5 shall be effective on the first day of the first calendar quarter six years following applicable regulatory approval; or, in those jurisdictions where no regulatory~~ approval ~~is required,~~, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

~~5.4.~~5.2.5 By the first day of the first quarter, six calendar years following Board of Trustees ~~adoption.~~ approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirement R5.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its ~~new or existing~~ generating unit ~~or generating plant~~ shall set such protective relaying so that ~~it~~the frequency protective relaying does not operate to trip the unit within the "no trip zone" of PRC-024 Attachment 1, ~~unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit.~~[2]subject to the following exceptions: *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Long-term Planning]*

~~1.1. A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec.~~

~~1.2.~~• ~~A generating unit or generating plant~~ Generation may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.

• Generation may trip if clearing a system fault necessitates disconnecting the generation.

• Generation may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3 for an existing generating unit[3].

R2. Each Generator Owner that has generator voltage protective relaying[1~~1~~] activated to trip its ~~new or existing~~ generating unit ~~or generating plant~~ shall set its protective relaying such that ~~it~~the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection[4]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2 or within the voltage recovery characteristics of a location-specific Transmission Planner's study if the Transmission Planner allows less stringent voltage relay settings than those

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

~~[2] To include generators under construction, generators with an executed interconnection agreement or Power Purchase Agreement by the effective date of this standard, or generators with an executed equipment purchase contract and scheduled delivery of major components within 2 years of the effective date of Requirement R5 of Version 1 of this standard.~~

[3] To include generating units previously commissioned, or generating units under construction, or generating units with an executed interconnection agreement or power purchase agreement by the effective date of PRC-024-1 Requirement R5.

[4] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

required to meet PRC-024 Attachment 2 ~~caused by an event on the transmission system external to the generating plant per~~ subject to the following exceptions ~~operating conditions and relay settings, unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit[2] or generating plant.: *[Violation Risk Factor: High*~~: *[Violation Risk Factor: Medium*] *[Time Horizon: Long-term Planning]*

~~**2.1.** When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:~~.

~~**2.1.1.** If a Transmission Planner's study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner's voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.~~

~~**2.1.2.**~~ • Generation may ~~T~~tripping a ~~generator~~ in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) ~~is acceptable in the "no trip zone" of PRC-024 Attachment 2~~.

~~**2.1.3.**~~ • Generation may trip ~~I~~if clearing a system fault necessitates disconnecting the generation~~a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2~~.

~~**2.1.4.**~~ • ~~A g~~Generati~~o~~on~~g unit or generating plant~~ may trip by action of ~~if the~~ protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

• Generation may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3 for an existing generating unit.

R3. Each Generator Owner of an existing generating unit ~~or generating plant~~ shall document each known equipment limitation (excluding limitations that are caused by generator frequency and voltage protective ~~relay limitations~~relays) that prevents a generating unit ~~or generating plant~~, from meeting the criteria in Requirements R1 or R2 (but not limited to) including study results, experience from an actual event, or manufacturer's advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

3.1. The Generator Owner shall communicate the documented equipment limitation, or the removal of a previously documented equipment limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the equipment limitation or ~~to ensure the accuracy of planning studies and system modeling studies. The existing~~

~~generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with~~ or when either of the following ~~conditions~~occurs:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.
- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).

R4. Each Generator Owner of an existing generating unit ~~or generating plant shall provide an estimate of that unit's performance during Frequency/Voltage Excursions to each requesting entity~~shall provide an estimate of the time duration the existing generating unit will remain connected (considering performance of the auxiliary systems as well as the generator) if the unit were to experience a frequency or voltage excursion. The voltage or frequency profile at the point of interconnection is determined by dynamic simulation provided by ~~(~~a Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit and has requested the time duration estimate. The estimate is to be provided ~~or generating plant)~~ to the requesting Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner within 60 calendar days of receipt of a written request~~, to ensure the accuracy of planning studies and system modeling studies~~. ~~The estimate shall include:~~ If the Generator Owner expects the existing generating unit will remain connected for longer than 10 minutes, the estimate should indicate the existing unit is not expected to trip. The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment. Detailed unit performance studies are not required to develop the estimate. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection described by dynamic simulation provided by the Transmission Planner. If the Generator Owner expects the existing unit, generating plant will remain connected for longer than 10 minutes, the estimate should indicate the existing unit or generating plant is not expected to trip.

4.2. Identification of the bases for the estimates developed for 4.1 which may include, but is not limited to: experience, actual event histories, or sound engineering judgment.

R5. Each Generator Owner shall design, build, and maintain its new [5] unit or new generating plant so that it (including auxiliary systems) consistent with the parameters set forth in PRC-024 Attachments 1 and 2, such that the generation, when operating at or above the minimum sustainable generation threshold (and for a generating plant consisting of multiple units with total generation greater than 75 MVA gross aggregate nameplate rating, when the generating plant is producing at least 20 percent of the plant's aggregate nameplate capacity) will not trip due to a frequency excursion or voltage excursion at the point of interconnection, caused by an event on the transmission system external to the generating plant, ~~within~~subject to the ~~parameters set forth in PRC-024 Attachments 1 and 2 and in accordance with the following conditions and~~ following exceptions: *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Real-time Operations]*

~~5.1. (condition) When the generating unit or generating plant is operating at or above the minimum sustainable generation threshold.~~

~~5.1.1. For a generating plant consisting of multiple units with total generation greater than 75 MVA (gross aggregate nameplate rating), when the generating plant is producing at least 20 percent of the plant's aggregate nameplate capacity.~~

- ~~5.2.~~ ~~(exception)~~ For a new generating plant consisting of multiple units less than 20 MVA each with total plant generation greater ~~than75~~than 75 MVA (gross aggregate nameplate rating), up to 10 percent of the individual generating units may disconnect as a result of the frequency or voltage excursion.
- ~~5.3.~~ ~~(exception) A generating unit or generating plant~~If the Transmission Planner has provided the Generator Owner with location-specific voltage recovery characteristics as described in Requirement R2, Part 2.2, then the generation may operate to a less stringent voltage ride-through performance criterion than the duration curve identified in PRC-024 Attachment 2 ~~based on the location-specific voltage recovery characteristics if provided by the Transmission Planner as described in Requirement 2, Part 2.1.1~~consistent with those provided characteristics.
- ~~5.4.~~ ~~(exception) A generating unit or generating plant~~Generation may trip if this action is designed as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- ~~5.5.~~ ~~(exception) A generating unit or generating plant~~Generation may trip if clearing a system fault necessitates disconnecting the ~~generating unit or generating plant~~generation.

[5] ~~Excluding generators in service prior to the effective date of Requirement R5 of Version 1 of this standard and excluding generators referenced in Footnote 2.~~

~~5.6.~~• ~~(exception) A generating unit or generating plant~~Generation may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation. ~~The Reliability Coordinator may retroactively grant a temporary exemption for~~ If an equipment limitation is identified following a plant trip caused by a frequency or voltage excursion, the Reliability Coordinator may grant a retroactive temporary exemption for that limitation if the Generator Owner develops and implements an acceptable ~~Mitigation Plan~~plan to address the limitation.

~~5.7.~~• ~~(exception) A generating unit or generating plant~~Generation may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

R6. Each Generator Owner shall provide its generator protection trip settings to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner (that monitors or models the associated unit), within ~~30~~60 calendar days of receipt of a written request for the data, and within ~~30~~60 calendar days of any change to those previously requested trip settings unless otherwise directed by the requesting Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner~~, to ensure the accuracy of planning studies and system modeling~~. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence such as dated setting sheets, calibration sheets, or other documentation, that generator frequency protective relays have been set in accordance with Requirement R1.

M2. Each Generator Owner shall have evidence such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies, that generator voltage protective relays have been set in accordance with Requirement R2.

M3. Each Generator Owner shall have evidence that it has documented and communicated any equipment limitations (~~Protection System excluded~~excluding limitations that are caused by generator frequency and voltage protective relays) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

M4. Each Generator Owner shall have evidence such as a copy of the ~~performance~~estimate of time duration report and correspondence, such as dated e-mails, or other documentation that an estimate of the ~~performance~~time duration of its existing generating unit(s) as a result of a ~~Frequency Excursion~~frequency excursion or ~~Voltage Excursion~~voltage excursion has been communicated in accordance with Requirement R4, and copies of any requests it has received for that information.

M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a ~~Frequency Excursion~~frequency excursion or ~~Voltage Excursion~~voltage excursion as specified in Requirement R5, or evidence that a listed exception applied~~, or provide an attestation that the generating unit or generating plant did not trip~~.

M6. Each Generator Owner shall have evidence such as dated e-mails, correspondence or other evidence that it communicated generator protective relay settings to a requesting entity within ~~30~~60 calendar days of a request or change in setting(s) in accordance with Requirement R6 and copies of any requests it has received for that information~~.~~.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity~~The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall ~~keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

~~•~~ ~~The Generator Owner shall retain the latest evidence of~~retain evidence of compliance with Requirement R1 through R6, ~~Measure~~Measures M1 through M6; ~~and shall retain prior evidence~~ for 3 ~~calendar~~ years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, ~~it~~the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved ~~found compliant or~~ for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a ~~generator~~generating unit has no documented and communicated ~~technical~~equipment limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit has no documented and communicated ~~technical~~equipment limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the ~~conditions~~criteria specified in Requirement R2
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 30 calendar days but less than or equal to 40 calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 40 calendar days but less than or equal to 50 calendar days of identifying the limitation.	meeting the criteria in ~~h~~ Requirement R1 or R2 and communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 50 calendar days but less than or equal to 60 calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within ~~61~~60 calendar days of identifying the limitation.
R4	The Generator Owner provided an estimate of a unit's performance more than ~~30~~60 calendar days but less than or equal to ~~40~~70 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than ~~40~~70 calendar days but less than or equal to ~~50~~80 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than ~~50~~80 calendar days but less than or equal to ~~60~~90 calendar days of a written request. ~~OR~~ ~~The Generator Owner failed to include documentation for one of the Parts specified in Requirement R4, Parts 4.1 and 4.2.~~	The Generator Owner failed to provide an estimate of a unit's performance within ~~61~~90 calendar days of a written request. ~~OR~~ ~~The Generator Owner failed to include any of the documentation specified in Requirement R4, Parts 4.1 and 4.2. .~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Generator Owner's generator tripped due to a ~~Frequency Excursion~~frequency excursion within the no-trip parameters set forth in Attachment 1 and did not meet any of the exceptions specified in the bulleted list within Requirement R5. OR The Generator Owner's generator tripped due to a ~~Voltage Excursion~~voltage excursion within the no-trip parameters set forth in Attachment 2 and did not meet any of the exceptions specified in the bulleted list within Requirement R5.
R6	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than ~~30~~60 calendar days but less than or equal to ~~40~~70 calendar days of any change to those trip settings ~~or limitations~~. OR	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than ~~40~~70 calendar days but less than or equal to ~~50~~80 calendar days of any change to those trip settings ~~or limitations~~. OR	The Generator Owner provided its generator protection trip settings as specified by Requirement R6 more than ~~50~~80 calendar days but less than or equal to ~~60~~90 calendar days of any change to those trip settings ~~or limitations~~. OR	The Generator Owner failed to provide its generator protection trip settings as specified by Requirement R6 within ~~60~~90 calendar days of any change to those trip settings ~~or limitations~~. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Generator Owner provided trip settings more than ~~30~~60 calendar days but less than or equal to ~~40~~70 calendar days of a written request.	The Generator Owner provided trip settings more than ~~40~~70 calendar days but less than or equal to ~~50~~80 calendar days of a written request.	The Generator Owner provided trip settings more than ~~50~~80 calendar days but less than or equal to ~~60~~90 calendar days of a written request.	The Generator Owner failed to provide trip settings within ~~60~~90 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

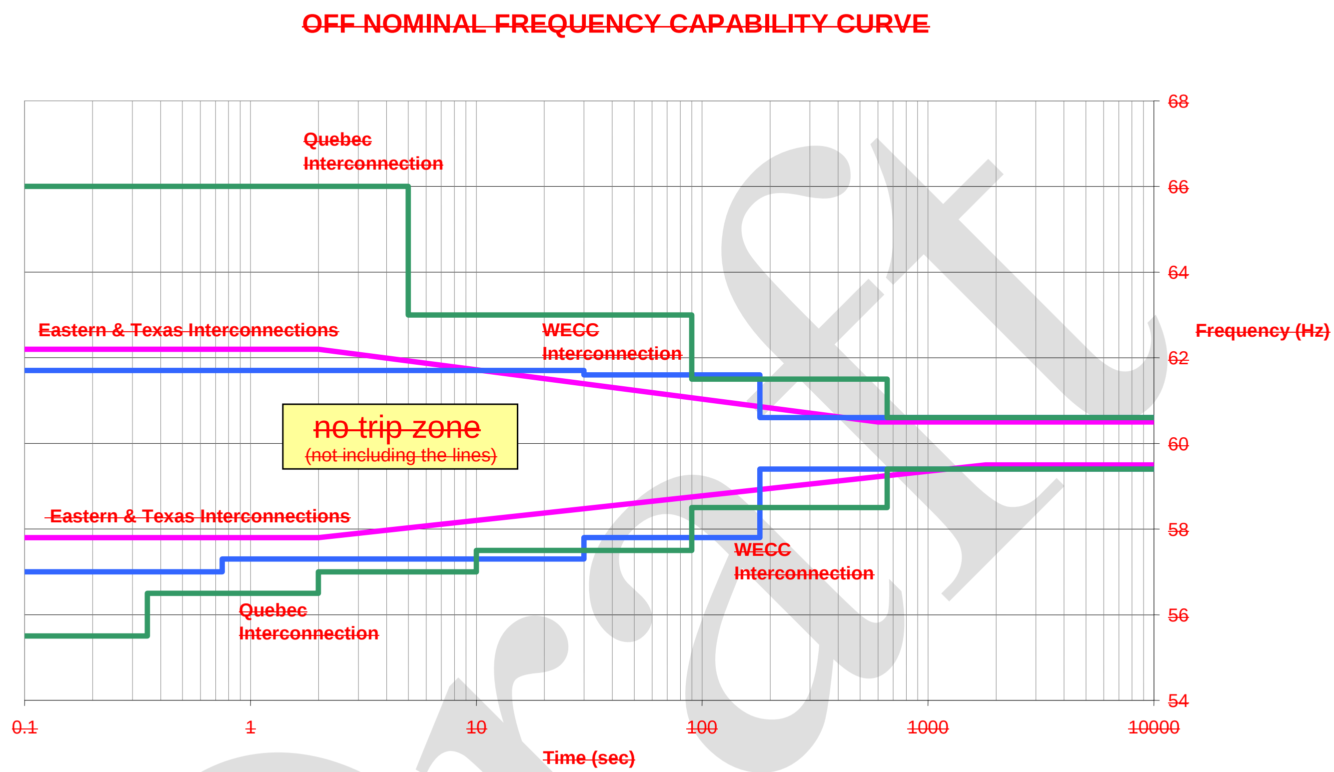
Version History

Version	Date	Action	Change Tracking

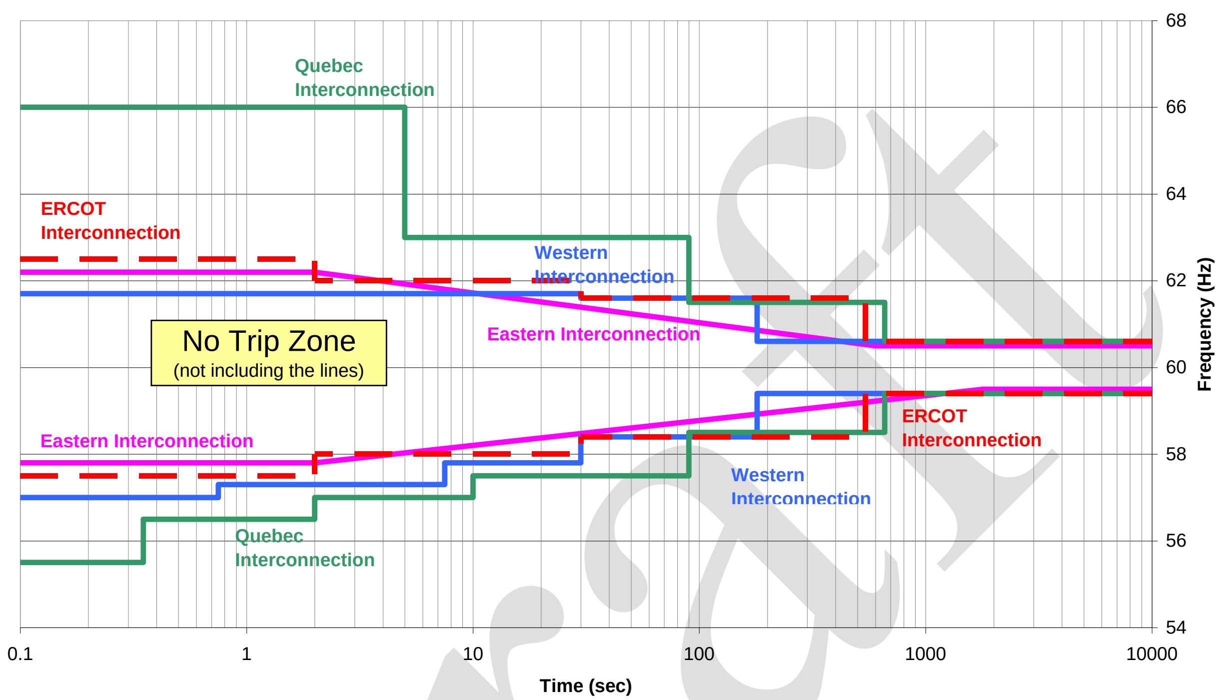
G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1



OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern ~~and Texas Interconnections~~Interconnection

High Frequency Duration		Low Frequency Duration	
~~Time (Sec)~~Frequency (Hz)	~~Frequency (Hz)~~Time (Sec)	~~Time (Sec)~~Frequency (Hz)	~~Frequency (Hz)~~Time (sec)
~~0 -~~ ≥62.2	~~62.2~~Instantaneous trip	~~0 – 2~~≤57.8	~~57.8~~Instantaneous trip
~~2 – 600~~≥60.5	~~62.41 – 0.686log(t)~~$10^{(91.1132-1.46*f)}$	~~2 – 1800~~≤59.5	~~57.63 + 0.575log(t)~~$10^{(1.7373*f-100.116)}$
~~> 600~~<60.5	~~60.5~~Continuous operation	> ~~1800~~59.5	~~59.5~~Continuous operation

~~WECC~~Western Interconnection

High Frequency Duration		Low Frequency Duration	
~~Time (Sec)~~Frequency (Hz)	~~Frequency (Hz)~~Time (Sec)	~~Time (Sec)~~Frequency (Hz)	~~Frequency (Hz)~~Time (sec)
~~0 – 30~~≥61.7	~~61.7~~Instantaneous trip	≤57.0~~ – 0.75~~	~~57.0~~Instantaneous trip
~~30 – 180~~≥61.6	~~61.6~~30	~~0.75 – 30~~≤57.3	~~57.3~~0.75
~~> 180~~≥60.6	~~60.6~~180	~~30 – 180~~≤57.8	~~57.8~~7.5
<60.6	Continuous operation	≤58.4	30
		~~> 180~~≤59.4	~~59.4~~180
		>59.4	Continuous operation

Quebec Interconnection

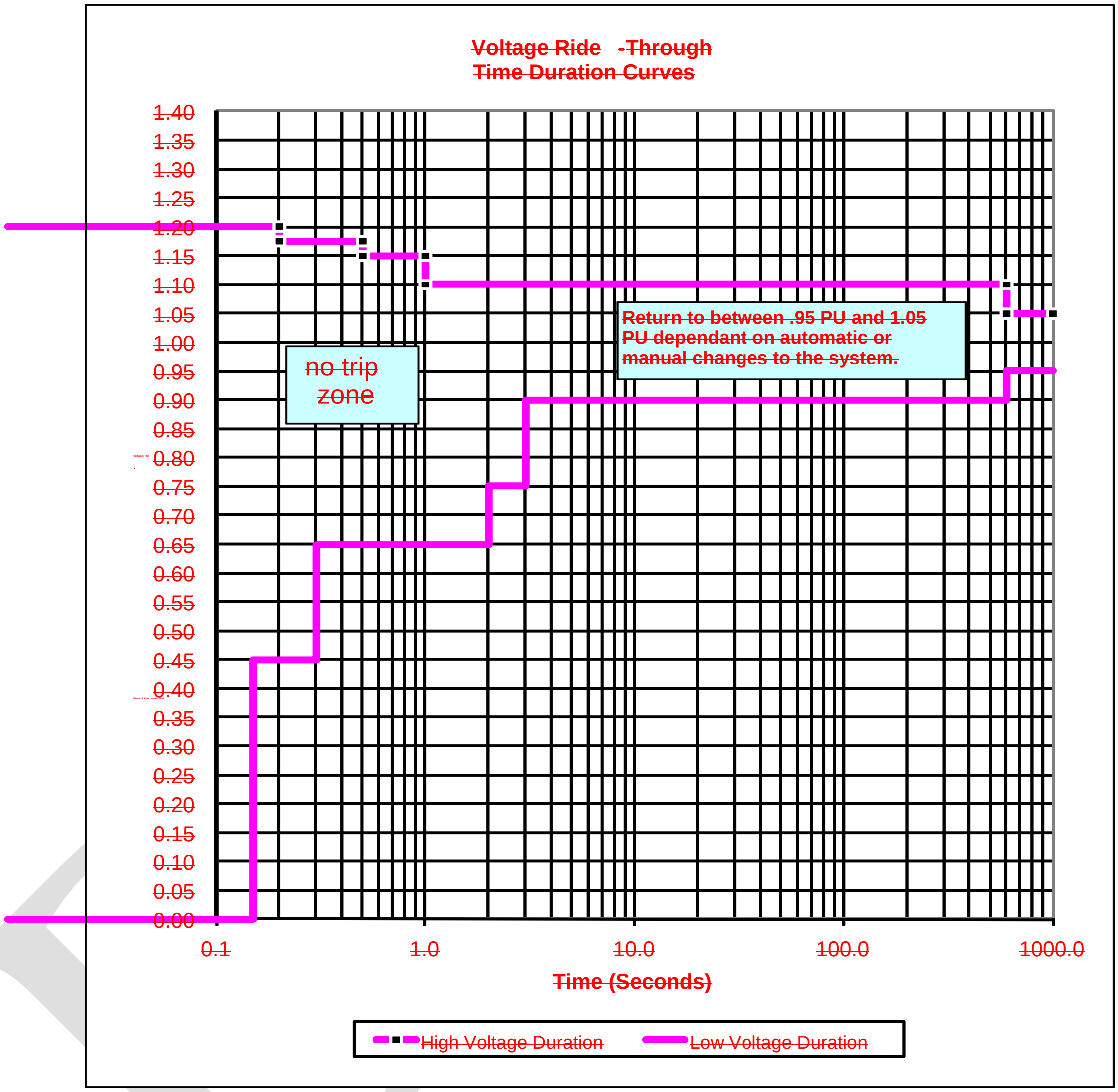
High Frequency Duration		Low Frequency Duration	
~~Time (Sec)~~Frequency (Hz)	~~Frequency (Hz)~~Time (Sec)	~~Time (Sec)~~Frequency (Hz)	~~Frequency (Hz)~~Time (Sec)
>66.0~~ – 5~~	~~66.0~~Instantaneous trip	~~0 – 0.35~~≤55.5	~~55.5~~Instantaneous trip
~~5 – 90~~≥63.0	~~63.0~~5	~~0.35 – 2~~≤56.5	~~56.5~~0.35
~~90 – 660~~≥61.5	~~61.5~~90	~~2 – 10~~≤57.0	~~57.0~~2
~~> 660~~≥60.6	~~60.6~~660	~~10 – 90~~≤57.5	~~57.5~~10
<60.6	Continuous operation	~~90 – 660~~≤58.5	~~61.5~~90
		~~> 660~~≤59.4	~~60.6~~660
		>59.4	Continuous operation

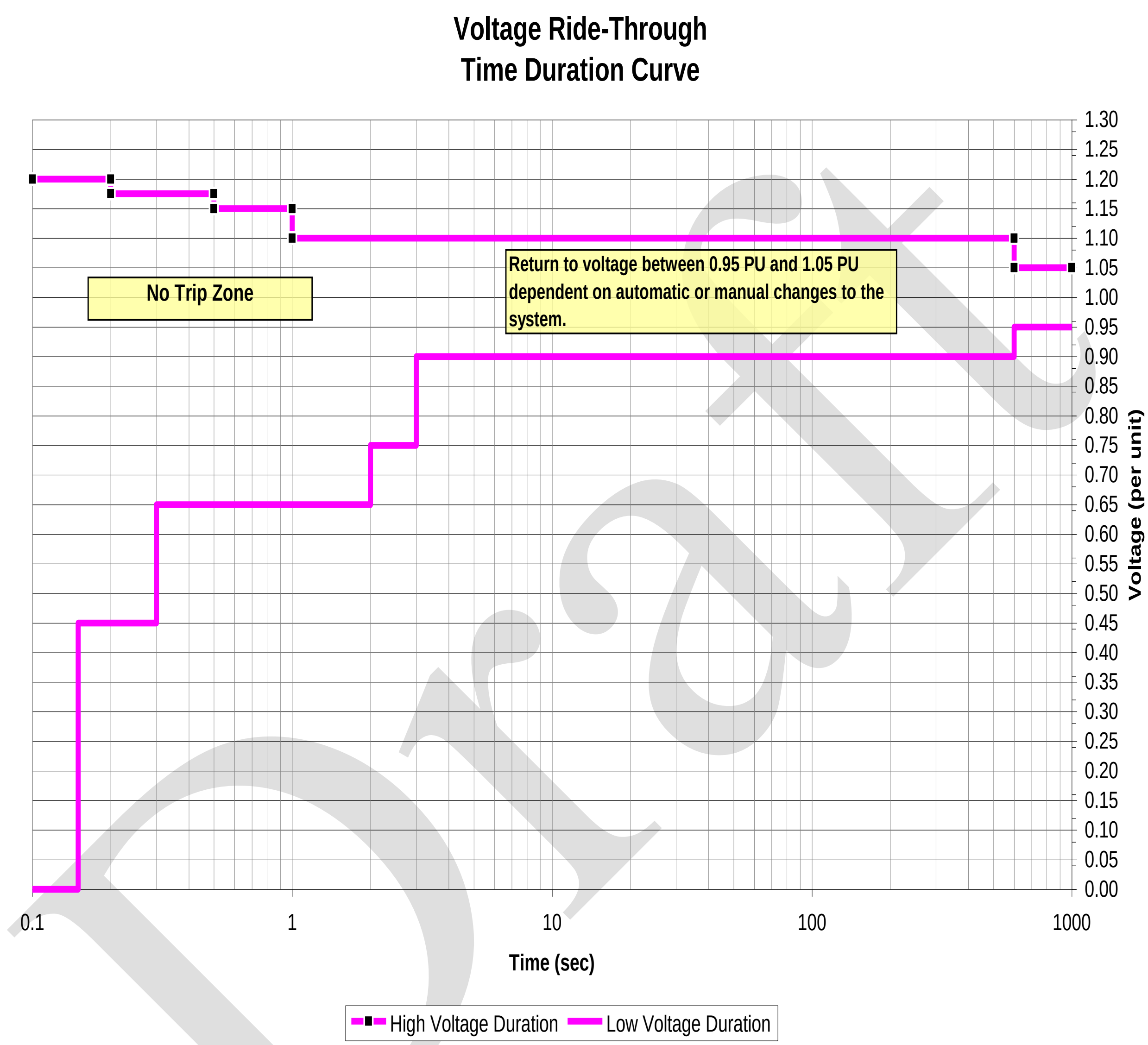
ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥62.5	Instantaneous trip	≤57.5	Instantaneous trip
≥62.0	2	≤58.0	2

≥61.6	30	≤58.4	30
≥60.6	540	≤59.4	540
<60.6	Continuous operation	>59.4	Continuous operation

PRC-024— Attachment 2




Voltage Ride-Through
Time Duration Curve
No Trip Zone
Return to voltage between 0.95 PU and 1.05 PU dependent on automatic or manual changes to the system.
1.30
1.25
1.20
1.15
1.10
1.05
1.00
0.95
0.90
0.85
0.80
0.75
0.70
0.65
0.60
0.55
0.50
0.45
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Voltage (per unit)
0.1
1
10
100
1000
Time (sec)
High Voltage Duration
Low Voltage Duration

Curve Data Points:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
~~Time (Sec~~Voltage (pu)	~~Voltage (p.u.)~~Time (sec)	~~Time (Sec~~Voltage (pu)	~~Voltage (p.u.)~~Time (sec)
~~0.20~~≥1.200	~~1.200~~Instantaneous trip	0.~~15~~00	0.~~000~~15
~~0.50~~≥1.175	~~1.175~~0.20	<0.~~30~~45	0.~~450~~30
≥1.~~00~~15	~~1.150~~0.50	~~2.00~~<0.65	~~0.650~~2.00
~~600~~≥1.10	1.~~100~~00	~~3.00~~<0.75	~~0.750~~3.00
>1.05	600	~~600~~<0.90	~~0.900~~600
≤1.05	Continuous operation	≥0.95	Continuous operation

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the ~~base~~nominal operating voltage specified ~~in the system models used~~ by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).

2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.

3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.

4. The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal.

5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest ~~phase-to-ground or~~ phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

~~6.~~1. Use the following assumptions to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:

    a. All of the units connected to the same transformer are online and operating,

    b. All of the units are at full nameplate real-power output.

    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals).

~~7.~~2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.

~~8.~~3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Performance During Frequency and Voltage Excursions

Approvals Required

PRC-024-1 – Generator Performance During Frequency and Voltage Excursions.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, six calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirement R5.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first quarter, six calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirement R5.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, R4, and R6 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Requirement R5 involves the performance of complete generation facilities (i.e. the prime mover, its fuel supply, and all auxiliary systems). To date, most Generator Owners have not specified this type of performance and the engineering companies designing generating facilities have not designed the facilities to ride through frequency and voltage excursions of the severity specified in PRC-024. In order to allow Generator Owners and architect/engineering companies time to develop new designs to meet R5, the SDT allows six years from regulatory approval for implementation.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Performance During Frequency and Voltage Excursions

Approvals Required

PRC-024-1 – Generator Performance During Frequency and Voltage Excursions.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.

- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.
- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.
- By the first day of the first calendar quarter, six calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirement R5.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.
- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.
- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.
- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6.
- By the first day of the first quarter, six calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirement R5.

~~Each Generator Owner shall verify that at least 33 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter one year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year following Board of Trustees adoption.~~

~~Each Generator Owner shall verify that at least 66 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter two years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years following Board of Trustees adoption.~~

~~Each Generator Owner shall verify that 100 percent of its applicable units are fully compliant with Requirements R1, R2, R3, R4, and R6 by the first day of the first calendar quarter three years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter three years following Board of Trustees adoption. Requirement R5 shall be effective on the first day of the first calendar quarter six years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six years following Board of Trustees adoption.~~

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, R4, and R6 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a ~~three~~five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than ~~three~~ fiveyears are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Requirement R5 involves the performance of complete generation facilities (i.e. the prime mover, its fuel supply, and all auxiliary systems). To date, most Generator Owners have not specified this type of performance and the engineering companies designing generating facilities have not designed the facilities to ride through frequency and voltage excursions of the severity specified in PRC-024. In order to allow Generator Owners and architect/engineering companies time to develop new designs to meet R5, the SDT allows six years from regulatory approval for implementation.

Project 2007-09 - Generator Verification

Unofficial Comment Form
MOD-026-1

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to MOD-026-1. Comments must be submitted by 8 p.m. ET **October 29, 2012**. If you have questions please contact Stephen Crutchfield at Stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information:

The GVSDT posted the draft standard, MOD-026-1, February 29 – March 29, 2012 for a formal comment period and successive. The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

The vast majority of the industry commenters agreed with the concept of specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. The GVSDT received comments regarding other aspects of the standard. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1. Also, some commenters were concerned that Table 1 inferred that plants with complex reactive coordination controllers may be unduly exempted from being applicable. The SDT clarified that for plants that include devices that provide dynamic voltage regulation (such as a STATCOM, DVAR or SVC, commonly found in Renewable Plants), these devices should be included in the model and should be validated. The intent of this language was to exempt only those units or plants that did not contain any closed loop voltage regulation function. The SDT added some clarifying verbiage to the appropriate row in Table 1 that ultimately references Footnote 1 in the standard.

Most of industry commented that they agreed with the guidance provided by the SDT on the periodicity aspects of Attachment 1. Many commenters did not correlate the guidance on the periodicity aspects of Attachment 1 to the examples “above” in the Background section of the Comment Form. Please see the Summary Consideration section for Question 5 as there were several comments regarding the periodicity examples.

The majority of the industry commenters agreed with specifying the capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, many of the commenters pointed out that neither the net or gross calculation was specified in the standard and suggested the SDT use the "net" calculation. As such, the SDT has revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Finally, the SDT moved the details of the capacity factor exemption concept from a footnote in the Applicability section to a row (Row 7) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 4).

The following modifications to the draft standard were incorporated as a result of industry comments:

1. A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".
2. The SDT has refined verbiage and the format in the standard applicability and Part 2.1 to clarify the use of individual and aggregate models for plants.
3. The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.
4. The SDT replaced "Planning Coordinator" with "Transmission Planner" in the standard. The Functional Model for the Transmission Planner is more in line with the task described in the standard.
5. The SDT revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.
6. Subpart 2.2 has been re-worded and merged into Subpart 2.1. The new verbiage makes it clear that the expert performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.
7. The SDT has refined section 4.2.1, 4.2.2, and 4.2.3 of the standard applicability.
8. The SDT has re-formatted the Periodicity Table (Attachment 1) to make it clearer that the table is included.
9. Revised the Periodicity Table (Attachment 1) extensively for clarity, including removing specificity regarding when the voltage excursion used for model verification had to be

captured. This resulted in a modification of the required times for re-verifying the model for exception (Requirements R3 and R4) type activities.

10. The SDT made corrections to VSL verbiage (less than or equal to with respect to days late) and replaced Planning Coordinator with Transmission Planner.

11. In Requirement R5, in describing checking the actual equipment to determine if updated model data could be obtained, the expression “walk down” was replaced by “on-site review” of the equipment.

12. The term “inertia” was modified to “total inertia” in Subpart 2.1.3 as some industry commenters expressed concern that reference to “inertia” only would lead to submittal of an inertia constant reflective only of the generator, as opposed to all of the mass attached to the shaft.

13. In Subpart 2.1.1, the specific reference to point of interconnection has been removed. The location where the unit’s response is measured is left to the model verification expert.

14. The second bullet in Requirement R1 has been modified to be the same style and sentence structure used in the first bullet of Requirement R1.

15. The SDT has removed the term “generating plant / Facility” and replaced it with “individual generating plant consisting of multiple generation units that are directly connected at a common BES bus” only from various sections of the applicability section of the standard for clarity.

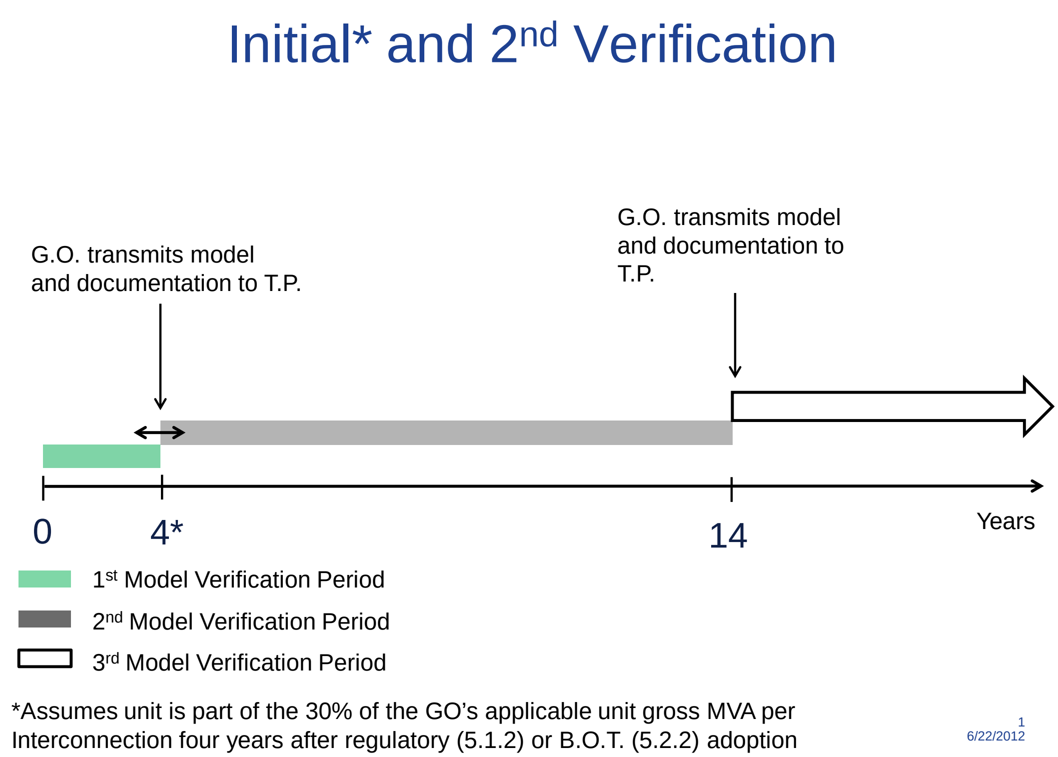
16. The SDT modified the phrase "generator excitation control system and plant volt/var control functions” to “generator excitation control system or plant volt/var control functions” to recognize that the use of the phrase “or” is technically correct the vast majority of the time.

Periodicity Table (Attachment 1) for MOD-026-1:

Based on industry comments from the last posting, the GVSDT modified the Periodicity Table (Attachment 1) to make it to make it significantly simpler and concise. In an effort to re-enforce the resulting modifications detailed in the current draft of the Periodicity Table, the following examples are offered by the GVSDT to aid industry in understanding the proposed model verification periodicity:

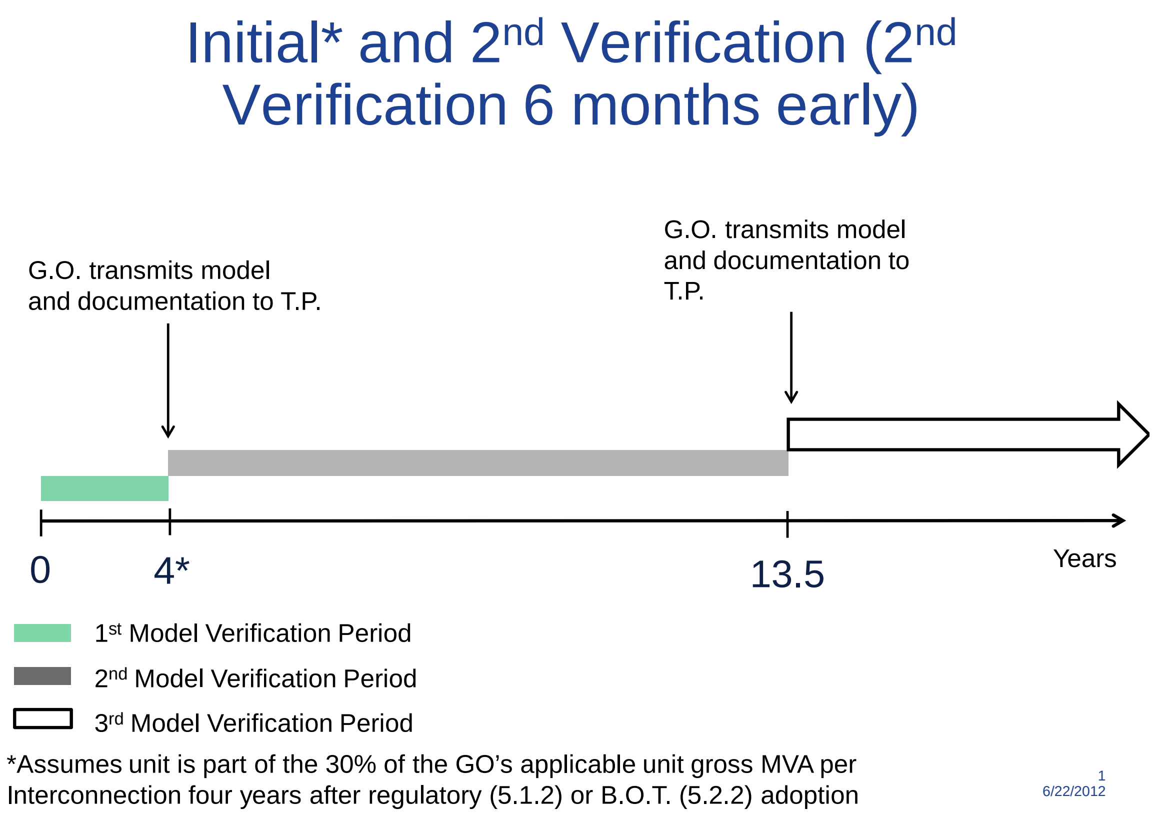
Periodicity Example 1:

The following timeline depicts a model which is initially verified, and then is verified again after a 10-year period. It is assumed that a unit is part of the 30% of the Generator Owners applicable unit's gross MVA per Interconnection four years after regulatory or NERC B.O.T. adoption used to meet the Effective Date requirements for Requirement R2. The requirements detailing activities by exception do not occur (Requirements R3 – R5) – which is expected to be the situation for the majority of the time. Note that the date of the collection of a recording of the actual equipment response to a voltage excursion is not needed to satisfy compliance. The recording of the actual equipment response simply has to occur in a timeframe which allows the GO time to finish verification and subsequently transmit the verified model including the verification documentation and model data by the required dates in the Periodicity Table. For this example, those required dates are Year four (first day of the first calendar quarter following regulatory or B.O.T. approval) – then 10 years after the submittal of the previous verification [Year 14] – then, again, 10 years after the submittal of the previous verification [Year 24]:



Periodicity Example 2:

The second example is much like Example 1. The only difference is that for the second verification, the Generator Owner finished model verification and submitted to its Transmission Planner the verified model including the model verification documentation and model data six months early. Regarding the third verification (which is not shown on the example below), the GO would be required to submit the verified model including the model verification documentation and model data on or before 10 years after the submittal of the previous verification (i.e., Year 23.5 or earlier).



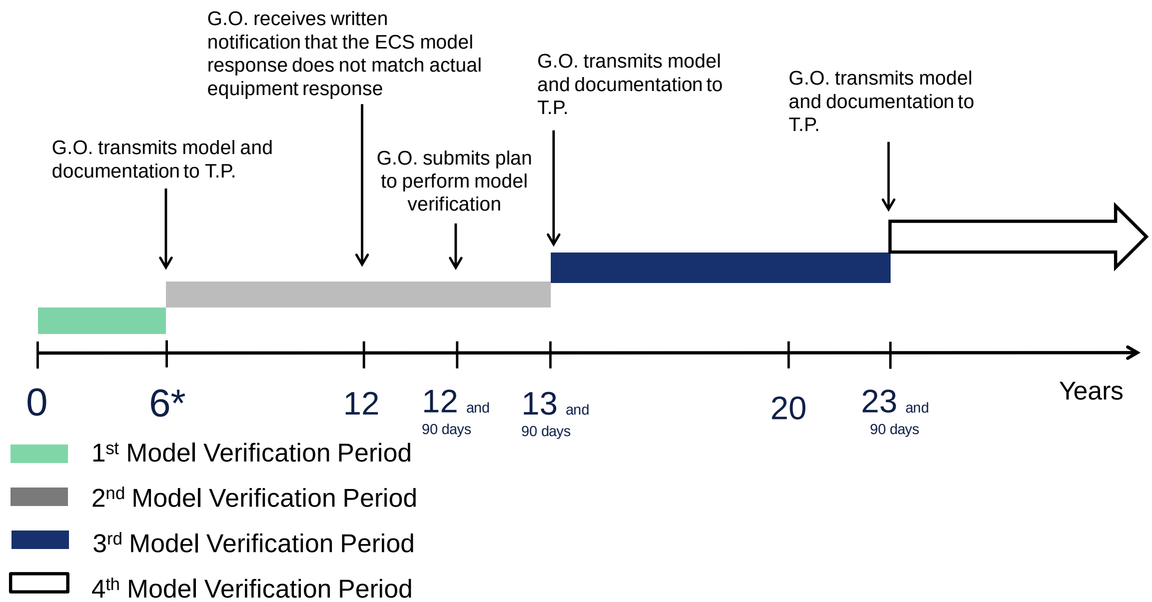
Periodicity Example 3:

In the third example, it is assumed that a unit is part of the 50% of the Generator Owners applicable unit's gross MVA per Interconnection six years after regulatory or NERC B.O.T. adoption used to meet the Effective Date requirements for Requirement R2. Following the initial verification, the third example details a scenario which the SDT anticipates would rarely occur. Specifically, the scenario assumes that at sometime after the initial verification, the Generator Owner receives written notification that there is evidence that the model does not accurately predict the actual response of the equipment. As detailed in Requirement R3, the Generator Owner has 90 days to respond to the notice. The Generator Owner may respond that the model is still appropriate, or submit model changes – or it may submit a plan to re-verify the model. The example below assumes that later – i.e., the Generator Owner submits a plan to re-verify the model on the 90th day.

From that point, per the Periodicity Table, the Generator Owner has 365 days to record and collect equipment response for a voltage excursion, perform model verification, and transmit the model and model verification documentation and data to the Transmission Planner. Regarding the third verification, the GO would be required to submit the verified model including the model verification documentation and model data on or before 10 years after the submittal of the previous verification (i.e., Year 23 plus 90 days or earlier).

Finally, regarding the fourth verification (which is not shown in its entirety on the example below), the GO would be required to submit the verified model including the model verification documentation and model data on or before 10 years after the submittal of the previous verification (i.e., Year 33 plus 90 days or earlier).

Initial Verification*, G.O. receives written comments that model does not predict equipment response



*Assumes unit is part of the 50% of the GO's applicable unit gross MVA per Interconnection six years after regulatory (5.1.3) or B.O.T. (5.2.3) adoption

1
6/22/2012

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **The GVSDT has revised Attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

2. **The GVSDT has revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. Do you agree with these revisions? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

3. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

   Comments:

Project 2007-09 - Generator Verification

Unofficial Comment Form
PRC-024-1

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to PRC-024-1. Comments must be submitted by 8 p.m. ET **October 29, 2012**. If you have questions please contact Stephen Crutchfield at Stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The Generator Verification Standard Drafting Team posted PRC-024-1, Generator Performance During Frequency and Voltage Excursions from February 29 through March 29, 2012 for a 30 day concurrent comment / successive ballot period. The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

A slight majority of stakeholders were in agreement with the approach taken for Requirement R4. Of the stakeholders who did not agree with the approach, the reasons most often cited were that such estimates would not provide any reliability benefit, the estimates are difficult to calculate, and the time period allowed to respond to a request for an estimate (60 days) is too short. The SDT modified the structure of the requirement to clarify the intent and the limits of what entities could request a performance estimate, but did not change the time period allowed to respond.

A large majority of stakeholders indicated that they did not agree that it is technically achievable for new generation to meet the performance required in Requirement R5. The most common reason stated was that Attachment 1 did not correctly specify the WECC region underfrequency tripping limits. Other objections cited by more than one responder were that the curves in Attachments 1 and 2 are too stringent, that significant R&D work needs to be done on the design of a plant to meet the requirement, and that the cost of building such a plant would be too high with little corresponding gain in grid reliability. The SDT corrected the error in the Attachment 1 underfrequency curve and data table for the Western Interconnection. The SDT did not make any substantive changes to Requirement R5 since the SDT did not feel stakeholders presented valid arguments that the requirement could not be achieved technically, given that similar requirements are already in effect in other parts of the world.

Other specific revisions to the standard are:

- The Effective Date section was modified for Requirements R1, R2, R3, R4, and R6 to reflect a five-year implementation at the request of several stakeholders.
- The wording in Requirement R1 was revised for clarity, Part 1.1 (rate of change of frequency) was removed and new bulleted items were added for consistency with Requirement R2 at the request of several stakeholders.
- Minor changes in the wording in Requirement R2 were made to improve clarity at the request of several stakeholders.
- The structure of Requirement R4 was modified and minor wording changes were made to improve clarity at the request of several stakeholders, though no changes were made to the intent of the requirement.
- Part 5.1 and Subpart 5.1.1 were incorporated into the body of Requirement R5 so that the remaining Parts of this requirement describe exceptions (i.e. allowances to trip).
- Minor wording changes were made at the request of multiple stakeholders to clarify wording in Parts 5.1 – 5.6 of Requirement R5.
- The allowable time to respond to a request for generator protection settings in Requirement R6 was increased from 30 days to 60 days at the request of several stakeholders.
- The Violation Risk Factors for Requirements R1, R2, and R5 were changed from High to Medium at the request of several stakeholders.
- Minor wording changes were made to Measures M3, M4, and M5 were made for clarity at the request of several stakeholders.
- The time frame referenced in Measure M6 was modified to correlate with the change made in Requirement R6.
- The wording in the Data Retention section was revised at the request of one stakeholder and now reflects the wording used in other recently-approved standards.
- Minor changes were made in the VSL's for Requirements R1, R2, R3, and R4 to add clarity or correct errors mentioned by several stakeholders.
- The wording in the Severe VSL for Requirement R5 was revised to add a reference to Parts 5.1 – 5.6 and the tardiness levels in the Requirement R6 VSL's were revised to reflect the change in the requirement.
- The underfrequency curve for the Western Interconnection and corresponding data table were corrected in Attachment 1 at the request of many stakeholders in the WECC region.
- Curves for the ERCOT Interconnection and a corresponding data table were added to Attachment 1 at the request of ERCOT.
- The term "base voltage" was replaced with "nominal operating voltage" in Clarification #1 to Attachment 2 at the request of several stakeholders.

- Minor wording changes were also made to Clarifications #2, and #5 to better convey the intent of the SDT in response to questions presented by several stakeholders.

You do not have to answer all questions. Enter All Comments in Simple Text Format.
Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

Questions

1. The GVSDT revised the VRFs for Requirements R1, R2 and R5 to "medium". Do you agree with this revision? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

2. The GVSDT revised R4 to improve clarity. Do you agree with this revision? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

3. Do you have any other comment, not expressed in questions above, for the GVSDT?

   Comments:

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-026-1 — Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-026-1:

There are six requirements in MOD-026-1. Four requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-026-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This requirement is administrative in nature for providing instructions and data used for performing model verification. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to provide a written response after receiving a request. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R5 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to

effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-026-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-026-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is timely. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness with completeness of information required for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R5:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating equal multiple parts criteria VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts also incorporate increments for tardiness consideration. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-026-1 — Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-026-1:

There are six requirements in MOD-026-1. Four requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-026-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that ~~is administrative in nature for the planning time frame that~~, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This requirement is administrative in nature for providing instructions and data used for performing model verification. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement ~~in a planning time frame~~ that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement ~~in a planning time frame~~ that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement ~~in a planning time frame~~ that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to provide a written response after receiving a request. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R5 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that ~~is administrative in nature for the planning time frame that~~, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state

or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-026-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-026-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is timely. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness with completeness of information required for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R5:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating equal multiple parts criteria VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts also incorporate increments for tardiness consideration. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s are a combination of completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 states "… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "	FERC Order 693	The GVSDT believes that Requirement R2 and the voltage ride through curves in PRC-024 Attachment 2 accomplish this. While the curves were developed based on three phase normally cleared faults located at a generating plant substation (the most severe condition for generating equipment), the curves cover voltages depressed as low as 0.65 per unit for two seconds, which the GVSDT feels will cover the Category B and C events of concern to the Commission. Requirement R5 directs all new generating facilities following approval of this standard to be designed, built and maintained so that they are able to ride through the excursions defined in the standard. For existing units, Requirement R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented technical reasons, but directs those generators to communicate that limitation to the RC, PC, TOP and TP so its performance can be modeled correctly. In addition, Requirement R4 allows the RC, PC, TOP, or TP to request an estimate of performance (ride through duration) from the GO for a defined excursion. The estimate would cover process upsets to the generating equipment that might result in a delayed trip, even if the

Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		generator protection itself did not cause a trip.
Paragraph 1787 also states "… the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented technical limitations. The GVSDT believes that NRC requirements qualify as technical limitations for the purposes of this standard.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Performance During Frequency and Voltage Excursions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:

There are six requirements in PRC-024-1. Three of the Requirements (R1, R2, and R5) were assigned a "Medium" VRF and the remaining three requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 and R5, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. . Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The “Lower” VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 contains Parts that are procedural in nature defining criteria associated with the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires an estimate of performance and is somewhat similar in concept with both PRC-009-0 Requirement R1 and PRC-014-0 Requirement R2, both of which reference protection analysis or assessment for determining adequacy. In addition, as is generally the case with reliability standard VRF definitions for analysis & assessment planning type requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to estimate performance during a frequency or voltage excursion is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to

adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to estimate performance during a frequency or voltage excursion. Requirement Parts and obligations are lower risk procedure based criteria for the main requirement. The "Lower" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying conditions and exceptions for satisfying the main requirement during external events. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R2, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires generation to remain connected during external events and as such does not have strong correlation to similar reliability goals listed in different reliability standards. This is similar in scope to Requirement R1 but is applied to new units rather than existing units. Therefore this requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to remain connected during an external event is a requirement during real-time operation that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 reliability objective is to remain connected during an external event. Requirement Parts specify conditions and exceptions elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The “Lower” VRF assigned is based on the reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's reflect increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner per the procedure criteria specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements. Requirement Parts merely identify conditions and exceptions for determining binary VSL status.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate binary methodology. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions and exceptions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Performance During Frequency and Voltage Excursions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:
There are six requirements in PRC-024-1. Three of the Requirements (R1, R2, and R5) were assigned a "~~High~~Medium" VRF and the remaining three requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 and R5, both of which were assigned a "Medium" VRF~~; which remaining standard requirements rationally relate by defining documentation, estimation, expectations during external events, and response expectations~~.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability,

separation or cascading would require other standards requirements to be violated. ~~In addition, and as is generally the case with PRC standard VRF definitions, t~~This requirement is assigned a "~~High~~Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. ~~could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition~~. Therefore the assigned "~~High~~Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 ~~high risk~~reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium~~High~~" VRF assigned is based on the ~~high risk~~reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5, both of which were assigned a "Medium" VRF~~; which remaining standard requirements rationally relate by defining documentation, estimation, expectations during external events, and response expectations~~.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. ~~In addition, and as is generally the case with PRC standard VRF definitions, t~~This requirement is assigned a "~~High~~Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. ~~could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.~~ Therefore the assigned "Medium~~High~~" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 ~~high risk~~reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium~~High~~" VRF assigned is based on the reliability ~~high risk~~ objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 ~~high risk~~reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The "Lower" VRF assigned is based on the ~~high risk~~reliability objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 contains Parts that are procedural in nature defining criteria associated with the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires an estimate of performance and is somewhat similar in concept with both PRC-009-0 Requirement R1 and PRC-014-0 Requirement R2, both of which reference protection analysis or assessment for determining adequacy. In addition, as is generally the case with reliability standard VRF definitions for analysis & assessment planning type requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to estimate performance during a frequency or voltage excursion is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 ~~high risk~~reliability objective is to estimate performance during a frequency or voltage excursion. Requirement Parts and obligations are lower risk procedure based criteria for the main requirement. The "Lower" VRF assigned is based on the ~~high risk~~reliability objective specified.

VRF for PRC-024-1, Requirements R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying conditions and exceptions for satisfying the main requirement during external events. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R2, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires generation to remain connected during external events and as such does not have strong correlation to similar reliability goals listed in different reliability standards. ~~A good approximation in regards to maintaining stable and continuous power operations can be found in standards BAL-002-0 and EOP-008-0; both of which possess a High VRF~~This is similar in scope

to Requirement R1 but is applied to new units rather than existing units. Therefore this requirement is assigned a "Medium~~High~~" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to remain connected during an external event is a requirement during real-time operation that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. ~~could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.~~ Therefore the assigned "Medium~~High~~" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 ~~high risk~~reliability objective is to remain connected during an external event. Requirement Parts specify conditions and exceptions elements that establish main requirement criteria for completeness. The "Medium~~High~~" VRF assigned is based on the ~~high risk~~reliability objective specified.

VRF for PRC-024-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 ~~high risk~~reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The "Lower" VRF assigned is based on the ~~high risk~~reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness. The Requirement Parts incorporate procedure based criteria elements incorporated as equal multiple parts rationale for completeness of the main Requirement. Requirement Parts are conditions that, if not performed, represent noncompliance of increasing severity based on the number of conditions not observed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements with additional consideration for completeness of listed parts and also increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner per the procedure criteria specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements. Requirement Parts merely identify conditions and exceptions for determining binary VSL status.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate binary methodology. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions and exceptions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-09 – Generator Verification

Successive Ballots and Non-Binding Polls open through 8 p.m. Monday, October 29, 2012

Now Available

Successive ballots are open for the following standards through **8 p.m. Eastern on Monday, October 29, 2012**:

- Draft 3 of **MOD-025-2** – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability,
- **MOD-027-1** – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions,
- **PRC-019-1** – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection,
- Draft 4 of **MOD-026-1** – Verification of Models and Data for Generator Excitation Control Systems Functions and Plant Volt/Var Control Functions, and
- **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions

Instructions
Members of the ballot pools associated with this project may log in and submit their votes for the Standards and opinions in the non-binding polls of the associated VRFs and VSLs by clicking here.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form links shown below. During the ballot window, balloters who wish to submit comments with their ballot *may no longer enter comments on the balloting screen*, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.

- MOD-025-2 ballot
- MOD-027-1 ballot
- PRC-019-1 ballot
- MOD-026-1 ballot
- PRC-024-2 ballot

Next Steps
The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background
The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

These standards were revised and posted for subsequent comment periods. The drafting team incorporated industry feedback to improve the standards and has posted them for a concurrent comment and ballot period.

Additional information is available on the project page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2007-09 Generator Verification

Formal Comment Period Now Open: September 28, 2012 – October 29, 2012

Upcoming:
Successive Ballots and Non-binding Polls: October 19 – October 29, 2012

Now Available

A formal comment period for:

- Draft 3 of **MOD-025-2** – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability,
- **MOD-027-1** – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions,
- **PRC-019-1** – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection,
- Draft 4 of **MOD-026-1** – Verification of Models and Data for Generator Excitation Control Systems Functions and Plant Volt/Var Control Functions, and
- **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions

is open through **8 p.m. Eastern on Monday, October 29, 2012.** Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, October 19, 2012** through **8 p.m. Eastern on Monday, October 29, 2012.**

Instructions for Commenting
A formal comment period for all five Generator Verification standards is open through **8 p.m. Eastern on Monday, October 29, 2012.**

Please use the links below to the electronic comment forms to submit comments:

MOD-025-2
MOD-027-1
PRC-019-1
MOD-026-1
PRC-024-1

If you experience any difficulties in using the electronic forms, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form links shown above. During the ballot window, balloters who wish to submit comments with their ballot *may no longer enter comments on the balloting screen*, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

- MOD-025-2 ballot bp-2007-09_MOD-025-2_in@nerc.com
- MOD-027-1 ballot bp-2007-09_MOD-027-1_in@nerc.com
- PRC-019-1 ballot bp-2007-09_PRC-019-1_in@nerc.com
- MOD-026-1 ballot bp-2007-09_MOD-026-1_in@nerc.com
- PRC-024-1 ballot bp-2007-09_PRC-024-1_in@nerc.com

Next Steps

Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will be conducted beginning on Friday October 19, 2012 through 8 p.m. Eastern on Monday, October 29, 2012.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

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recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

These standards were revised and posted for subsequent comment periods. The drafting team incorporated industry feedback to improve the standards and has posted them for a concurrent comment and ballot period.

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Standards Announcement

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Formal Comment Period Now Open: September 28, 2012 – October 29, 2012

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- Draft 3 of **MOD-025-2** – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability,
- **MOD-027-1** – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions,
- **PRC-019-1** – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection,
- Draft 4 of **MOD-026-1** – Verification of Models and Data for Generator Excitation Control Systems Functions and Plant Volt/Var Control Functions, and
- **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions

is open through **8 p.m. Eastern on Monday, October 29, 2012.** Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, October 19, 2012** through **8 p.m. Eastern on Monday, October 29, 2012.**

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MOD-027-1
PRC-019-1
MOD-026-1
PRC-024-1

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- MOD-027-1 ballot bp-2007-09_MOD-027-1_in@nerc.com
- PRC-019-1 ballot bp-2007-09_PRC-019-1_in@nerc.com
- MOD-026-1 ballot bp-2007-09_MOD-026-1_in@nerc.com
- PRC-024-1 ballot bp-2007-09_PRC-024-1_in@nerc.com

Next Steps

Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRFs and VSLs will be conducted beginning on Friday October 19, 2012 through 8 p.m. Eastern on Monday, October 29, 2012.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

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Standards Announcement

Project 2007-09 – Generator Verification

Successive Ballot Results

Now Available

Successive ballots of all five Generator Verification standards and non-binding polls of the associated VRF/VSLs concluded on Monday, October 29, 2012 (some of the ballots and non-binding polls were extended until a quorum was reached).

Voting statistics for each of the ballots are listed below, and the Ballots Results page provides a link to the detailed results.

Standard	Approval	Non-binding Poll Results
MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions and Plant Volt/Var Control Functions	Quorum: 75.55% Approval: 76.50%	Quorum: 75.88% Supportive Opinions: 79.95%
PRC-024-1 – Generator Performance During Frequency and Voltage Excursions	Quorum: 75.00% Approval: 57.24%	Quorum: 75.40% Supportive Opinions: 55.90%
MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	Quorum: 83.61% Approval: 68.31%	Quorum: 77.94% Supportive Opinions: 70.72%
MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	Quorum: 82.34% Approval: 71.53%	Quorum: 78.06% Supportive Opinions: 74.18%
PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	Quorum: 82.07% Approval: 70.64%	Quorum: 78.51% Supportive Opinions: 69.39%

Next Steps
The standard drafting team (SDT) will consider all comments submitted, and based on the comments will determine whether to make additional changes. If the SDT determines that no substantive changes are required to address the comments on a particular standard, a recirculation ballot of that standard will be conducted. If the SDT determines that substantive changes are required on a standard, the revised standard will be submitted for quality review and subsequently posted for a successive ballot.

Background
The purpose of Project 2007-09 Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The Project 2007-09 Generator Verification SDT based its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The SDT has recently moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1.

The SDT has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid-2006 through mid-2007:

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- MOD-026-1 —Verification of Models and Data for Generator Excitation Control System Functions and Plant Volt/Var Control Functions
- MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

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Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2007-09 Successive Ballot MOD-026-1
Ballot Period:	10/19/2012 - 11/2/2012
Ballot Type:	Successive
Total # Votes:	241
Total Ballot Pool:	319
Quorum:	**75.55 % The Quorum has been reached**
Weighted Segment Vote:	76.50 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	85	1	43	0.741	15	0.259	7	20
2 - Segment 2.	6	0.4	2	0.2	2	0.2	1	1
3 - Segment 3.	68	1	30	0.714	12	0.286	9	17
4 - Segment 4.	25	1	14	0.875	2	0.125	3	6
5 - Segment 5.	76	1	31	0.633	18	0.367	7	20
6 - Segment 6.	42	1	22	0.786	6	0.214	4	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	5	0.5	0	0	1	2
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.5	4	0.4	1	0.1	0	2
Totals	**319**	**6.6**	**153**	**5.049**	**56**	**1.551**	**32**	**78**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff		
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		

1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Southwestern Power Administration	Gary W Cox		
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David Anderson		

3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	

5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Cowlitz County PUD	Bob Essex	Negative	
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	

6	Constellation Energy Commodities Group	Brenda L Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8		Merle Ashton		
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Ballot Results	
Ballot Name:	Project 2007-09 Successive Ballot PRC-024-1
Ballot Period:	10/19/2012 - 10/31/2012
Ballot Type:	Successive
Total # Votes:	237
Total Ballot Pool:	316
Quorum:	**75.00 % The Quorum has been reached**
Weighted Segment Vote:	57.24 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	82	1	34	0.607	22	0.393	9	17
2 - Segment 2.	6	0.4	3	0.3	1	0.1	0	2
3 - Segment 3.	68	1	18	0.439	23	0.561	8	19
4 - Segment 4.	25	1	7	0.467	8	0.533	4	6
5 - Segment 5.	76	1	21	0.429	28	0.571	6	21
6 - Segment 6.	42	1	15	0.536	13	0.464	4	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	4	0.4	1	0.1	1	2
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.5	4	0.4	1	0.1	0	2
Totals	**316**	**6.6**	**108**	**3.778**	**97**	**2.822**	**32**	**79**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith		
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff		
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Negative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	Marilyn Brown		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David Anderson		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	

3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Cowlitz County PUD	Bob Essex	Negative	

5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Arizona Public Service Co.	Justin Thompson		
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6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda L Powell		
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6	Duke Energy Carolina	Walter Yeager	Negative	

6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner		
8		Brendan Kirby	Affirmative	
8		Merle Ashton		
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	

Non-binding Poll Results

Project 2007-09 MOD-026-1

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-09 Non-binding Poll MOD-026-1
Poll Period:	10/19/2012 - 11/2/2012
Total # Opinions:	236
Total Ballot Pool:	311
Summary Results:	75.88% of those who registered to participate provided an opinion or an abstention; 77.10% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		

1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	

1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Southwestern Power Administration	Gary W Cox	Abstain	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	Southwest Power Pool	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	

3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities	Tim Beyrle		

	Commission			
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Cowlitz County PUD	Bob Essex	Negative	
5	CPS Energy	Robert Stevens		

5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	

5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	

6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
8		Edward C Stein	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Texas Reliability Entity	Larry D Grimm		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

NERC

Non-binding Poll Results

Project 2007-09 PRC-024-1

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-09 Non-binding Poll PRC-024-1
Poll Period:	10/19/2012 - 11/2/2012
Total # Opinions:	233
Total Ballot Pool:	309
Summary Results:	75.40% of those who registered to participate provided an opinion or an abstention; 52.72% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Entergy Services, Inc.	Edward J Davis		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		

1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff		
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		

1	Seattle City Light	Pawel Krupa	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
2	Alberta Electric System Operator	Mark B Thompson		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	Southwest Power Pool	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	

3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	

NERC

4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Cowlitz County PUD	Bob Essex	Negative	
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	

5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	

5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	

6	South California Edison Company	Lujuanna Medina		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
8		Edward C Stein	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Texas Reliability Entity	Larry D Grimm		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (46 Responses)
Name (32 Responses)
Organization (32 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (4 Responses)
Comments (46 Responses)
Question 1 (33 Responses)
Question 1 Comments (42 Responses)
Question 2 (33 Responses)
Question 2 Comments (42 Responses)
Question 3 (0 Responses)
Question 3 Comments (41 Responses)

Individual
Nazra Gladu
Manitoba Hydro
Yes
None.
Yes
Although Manitoba Hydro agrees with the concept proposed, it is difficult or sometimes impossible to get an exact match between simulated and measured responses. The drafting team should allow for some engineering judgment (for example, if the responses are within 5-10% of each other, the model could be considered to be a reasonable representation).
Section 2.1.2 - Manitoba Hydro suggests revising the text to read as follows: Manufacturer, model number (if available), and type of excitation control system and the plant volt/var control function (if installed). R2.1.4. - Manitoba Hydro proposes that only the text of "Model structure and data for the excitation control system" is kept. An excitation control system consists of generator and excitation system as per IEEE 421.1 and 421.5. 4.2 - The language immediately preceding the bullets is unclear (i.e. 'that meet the following' should possibly be reworded as 'provided they meet the following'). R1 -This requirement would be clearer if rewritten as 'Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner:' General Comment - Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?
Individual
Kathryn Zancanella
South Feather Power Project
Applicability section 4.2.2.2 describes an Individual Generating Plant as consisting of multiple generating units that are directly connected at a common BES bus with a total capacity greater than 75 MVA. It would help if there was a proximity element to the definition of "Individual Generating Plant." My question/comment comes from the fact that I have three single unit powerhouses with a combined total capacity greater than 75 MVA connected to a single 115 kV radial line, with several miles of transmission line separating each unit from the other, but the radial line (which is owned by another entity) ultimately terminates at a single (common) point on a BES bus. Attached to this same radial transmission line are a distribution substation and another entity's small hydro plant, so it is not clear how this common point on a BES bus would be characterized.
Individual
xyz
lum
No
No
Individual

Darryl Curtis
Oncor Electric Delivery Company
No
Oncor does not support the position that the Transmission Planner (TP) is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the Planning Authority (PA) only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
No
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. For MOD-026-1 Section 4.2.4, Oncor takes the position that it is the decision of the PA not the TP who determines the basis for NERC applicability. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the applicability determination in Section 4.2.4, be the responsibility of the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Individual
Jim Watson
Dynegy
Yes
Yes
1. It’s not clear what the difference is between R3 and R5. Suggest combining these into one Requirement. MOD-027-1 which also requires model validation does not have a Requirement similar to R5. 2. Requirement 2.1.1 does not state how much of a step change is required when testing the exciter controls. A commonly used step is 2% but this is not clear.
Group
Northeast Power Coordinating Council
Guy Zito
Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
There is a problem with the threshold in the standard of 100MVA units. We would suggest that this be in line with the BES DEF and reduce this threshold to 20MVA. Why has the threshold been increased? If the data has to be provided for LGIA under the Tariff then we should be verifying the data. There is also inconsistency between the

standards posted for comment I.E. PRC-019-1. We would like to see better consistency for the thresholds between all the standards under this project and with the other projects associated with generator thresholds.
Individual
Lynn schmidt
NIPSCO
Verification requirements would be burdensome, e.g., model response by staged testing or comparison with a system disturbance may be of only limited value. Another basic problem with this standard is the unnecessary back and forth between generation owners and transmission planners in the data development and collection. This standard could be greatly simplified for all involved parties with reporting requirements similar to MOD-025 where the generation owner provides information to the transmission planner upon the installation of new equipment or the modification of existing equipment. Given the above, Transmission Planning recommends a vote against this standard in its present form.
Individual
Cristina Papuc
TransAlta Centralia Generation LLC
Yes
Yes
N/A
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
Since GO's typically do not have in-house expertise, they would either have to hire consultants to perform model verification or develop in-house expertise, including acquiring simulation software. Are such simulated models/software available today for this on the market? If not, has time been built into the implementation schedule for allowing such creation—it does not appear so? Also, the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units should be independent of the physical location.
No
It appears that without the word "and" in 4.2.4, this criterion of using NERC registration criteria would "trump" all the other interconnection requirements above. But, with the word "and" it indicates that any of the smaller registered units or blackstart resources would only be included in this standard if the Transmission Planner requires. The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.
The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC’s March 15, 2012 FFT Order to propose specific standards or requirements that should

be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip overspeed excursion. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed.
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
Group
pacificorp
ryan millard
Yes
Yes
Individual
Winnie Holden
PSEG
Yes
Yes
We voted "Negative" on this standard the reasons shown below. This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1. 1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a "team" with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as "applicable facilities," while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments: "The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states "Synchronous condensers are not currently addressed in the NERC Registry Criteria" However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency." The SDT responded as follows: "The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex

interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model." In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: "The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2." PRC-019-1: "The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers." We need to see "one" statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. This SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1. 2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1, R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all "modelers," the result will be outdated data in someone's model, which can have a bad result. The team should have one broad "data sharing" policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)
Yes
Yes
In general, Ingleside Cogeneration LP believes that a good working relationship between the Generator Owner and Transmission Planner includes a reasonable justification for any request that requires time and expense on the part of the other.
Ingleside Cogeneration LP agrees that the ability for Transmission Planners to effectively model and simulate actual system response to voltage transients can lead to reliability improvements. In addition, the technical veracity and implementation time frames in the latest version of MOD-026-1 are far improved over previous versions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R2) must contain language that focuses on the strength of the validation process – not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed – even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects.

Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
For Requirement 6, ATC recommends the wording at the end of the requirement to read “that includes how any of the following criteria are not met:” because the existing wording does not express that the criteria are not met when the model is not usable.
Individual
Ken Gardner
Alberta Electric System Operator (AESO)
1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. 3. Requirement R4, as written it appears owners of generating units that plan to change out the excitation control systems are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst believes there is a major disconnect/flaw between the Applicability Section (4.2. Facilities) and Requirement R2, part 2.1. This major flaw will create confusion on which generating units are required to be verified per the standard. ReliabilityFirst offers the following comments for consideration: 1. Requirements R2, Part 2.1 - There is a clear disconnect between the Applicability section of the standard (i.e. individual units/plants greater than 100MVA - Eastern or Quebec Interconnections) and Requirements R2, Part 2.1 which requires”… Verification of an individual unit less than 20 MVA.” Based on the Applicability section, units less than 20 MVA are not applicable under this standard. Furthermore, units under 20 MVA do not fall under the NERC Statement of Compliance Registry Criteria as criteria for registration purposes for GOs and GOPs. 2. Applicability Section 4.2. Facilities – ReliabilityFirst thanks the SDT for their justification for the 100 MVA threshold, but still believes that the Applicability should be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). Even though the 100 MVA threshold covers 80% of the connected MVA or greater for each Interconnection (in aggregate), depending on the geographic location (within the BES), that value may be much less. For example, if there is a certain load pocket in which the majority of the connected generation is lest that 100 MVA, the dynamic models would not be required to be verified per this standard. Thus not having verified accurate dynamic models for this specific location could hinder the reliability of the BES. ReliabilityFirst recommends changing the Applicability section to be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES).
VSL Requirement R6 – ReliabilityFirst still believes the VSL for Requirement R6 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” Requirement R6 clearly requires the Transmission Planners to “...notify the Generator Owner... “, while the corresponding VSL states “The Transmission Planner provided a written response to the Generator Owner indicating...” The VSL is adding additional requirements on the TP (i.e. provide written response) which are not required within the actual requirement (nowhere in R6 is the TP required to provide a written response). If it is the intent of the SDT to have the TP provide a written response, ReliabilityFirst recommends adding that language to the requirement.
Individual
Dale Fredrickson
Wisconsin Electric Power Company

No
In Row 4, the use of 350 MVA as the cutoff for “sister unit” treatment is not reasonable. We propose the limit can be increased to 500 MVA without any adverse reliability impacts. Also, in Row 5, the allowable time for existing units to be verified following an indication of model problems should be 2 years, rather than 1 year, since existing legacy units may require additional resources to understand and resolve the issues.
No
We propose that the requirements for a “technically justified unit” must also include the technical reasons why the unit under consideration is critical to the reliability of the BES.
1. In 4.2.1.2, the use of the term “directly connected at a common BES bus” suggests that wind farms are not applicable facilities, since wind generators are typically directly connected to a non-BES bus (e.g. 34.5 kv). We suggest that the applicability to wind farms be clarified more explicitly. 2. In R1, the present wording allows for the TP to provide only one of the three types of data, even if the GO requested all three. We suggest removing the wording, “one or more of”. 3. In R1, the present requirement is for the TP to provide instructions to the GO on how to obtain the acceptable models and associated block diagrams and data. We believe that since the TP is very familiar with this data and the GO may not be, it is far simpler and efficient for the TP to provide the actual data on request, not just the instructions on how to obtain it. 4. In R2.1.1, the GO is required to have documentation comparing the “model response” to the “recorded response”, in this case Voltage vs. Time. First, to determine the model response requires the ability to run dynamic studies. Generally the GO does not have the simulation capability or the subject matter experts required to perform dynamic system studies. It would seem that the intent of this requirement is that the GO must expend considerable resources to gain this capability, either internally or by other means. Is this the intent of the SDT? 5. In R3, the requirements for the written response to the TP need clarification. The term “either” would suggest there are two possible responses. However, there appear to be three possible responses. We suggest there needs to be a 4th possible response option for the GO, for the GO to initiate contact with the TP to schedule a meeting to discuss the technical issues with the model. The necessary collaboration between the GO and TP to understand the model deficiencies will require time, thus may require more than the 90 days to reconcile the model issues. 120 days is suggested. 6. In Section 5 Effective Dates: The considerable time and resources needed to get up to speed with model verification suggests there needs to be more time allowed in the earlier phases of the compliance timeline. We suggest using 20 percent in 4 years, 40 percent in 6 years, and 100 percent in 10 years.
Individual
Thad Ness
American Electric Power
Yes
The SDT should consider either removing MOD-026-1 R5 or merge R3 and R5 because a) MOD-026-1 R3 and R5 appear to have the same objective with similar wording and b) MOD-027-1 does not have the equivalent of MOD-026-1 R5. MOD-026-1 R6 ends with "...that includes the following:" yet whatever the SDT intended to follow is missing. Please note that subparts 1 through 3 are referenced in parenthetical statements within the respective requirements and that it does not make sense that these subpart criteria are also what needs to follow "...that includes the following:"
Group
Tennessee Valley Authority
Brandy Spraker
No
1. Attachment 1, Row Number 4, Recommend deleting “at the same physical location” from the Verification condition. The first condition is recommended to read “Existing applicable unit that is equivalent to another unit(s),” Justification is that if a GO has units that are equivalent and meet the “sister” criteria, the standard does not need to be restricted to the same physical location. The GO identical equipment at different physical locations are still equivalent.
No
1. The GVSDT had good intentions by having a very short requirement. However, I am not sure what the intent is. A few more descriptive words would help greatly.
None
Individual
Michael Falvo
Independent Electricity System Operator

No
The long periods in Attachment 1 introduce too much risk: the modeling assumptions (used to derive operating security limits and to make other operating and planning decisions) do not reflect the actual performance of equipment. It would be better for the standard not only to establish the maximum period that Transmission Planners and Generators Owners to complete tasks but also to require the Transmission Planners to establish shorter periods when necessary to reduce the risk to reliability to an acceptable level. In Ontario, Generator Owners have 30 days to transmit the verified model, documentation and data to the Transmission Planner. Generator Owners are also required to indicate immediately following testing whether the installed equipment performed as expected. This approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet requirements. Emerging from this process is the Generator Owner's conditional right to connect provided he meets an obligation to demonstrate the installed equipment behaves as well as assumed in the assessment process. In this way, the risk to reliability is reduced to an acceptable level as the exposure of the decision making process to flawed modeling assumptions is minimized Experience in Ontario has shown that units that were expected to have essentially the same performance often show much larger differences than expected when tested. What seems like small or obscure differences to a Generator Owner can be critical to a Transmission Planner. Row 4 in Attachment 1 should be amended to require the amount of verification on "sister" units to be accepted by the Transmission Planner. Attachment 1 Row 4 that allows for new or existing units that does not include an active closed loop voltage or reactive power control function should be changed. Given the size of the "applicable unit" virtually all units should be on voltage control unless specifically permitted by the Transmission Planner as is the case in Ontario. The adverse effects to reliability of not being on voltage control are well documented (Note1). The standard should be changed to put the onus on the Generator Owner of units not operating in voltage control to demonstrate continued operation in this mode does not have a material adverse effect on reliability. The standard should requirespecify the a process available for moving an "applicable unit" to closed loop voltage control when the Transmission Planner determines this is necessary. Note1: J.D. Hurley, L.N. Bize, C.R. Mummert C.R,The Adverse Effects of Excitation System Var and Power Factor Controllers, IEEE Transactions on Energy Conversion, Vol 14, No. 4, December 1999
Yes
a. No explicit NERC performance requirements for excitation system are a weakness. In Ontario, generating units are required to materially help regulate voltage as the Transmission Planner sets performance requirements for upper and lower ceilings, voltage response time, and stabilizer characteristics. This standard in its present form allows generators to continue to not materially help regulate voltage provided the documentation submitted to Transmission Planner is consistent with this lack of performance. b. In Ontario, experience has been that the models typically used by the Transmission Planner are not commonly employed by Generator Owners. The standard recognizes this in R1 by giving the obligation to the Transmission Planner to provide model block diagrams or data sheets to the Generator Owner. As the Transmission Planner may be unaware of practicable constraints on a unit and the Generator Owner may not be familiar with the reliability models; both parties must reach an accommodation on the details to verify the model. R2 should be changed so the Generator Owner is required to provide a model that has been verified by a method accepted by the Transmission Planner. c. The measured performance of the OEL, UEL, stator current limiter or any other automatic control system that alters the behaviour of the excitation system should be part of the Generator Owner submission to the Transmission Planner as limiter performance can affect reliability decisions. No limiter that imposes more restrictive limits than the required short term field and armature current requirements in ANSI/IEEE 50.13 should be implemented without the Transmission Planner's approval. d. The concept of "applicable unit" should be extended to include static var generators and similar devices. All facilities with an excitation control system and more than 100 MVA of capability should fall under this standard. e. Changes to the generator (e.g. rewinds or active power output increases) will affect excitation system performance. The standard should require re-testing following other modifications that the Transmission Planner can show with simulations will require modifications to the excitation system to improve reliability. For example, turbine replacements often provide increased active power capability. At higher levels of active power, the excitation system can materially change without coordinated changes to over-excitation limiters. f. R2.1 should be amended (see below) to add flexibility to include other practical combinations of units to be used for verification. For example, it can be more practicable to test wind and solar installation one feeder at a time but this is not allowable with the standard in its present form. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA (gross nameplate rating) may be performed using either an individual unit, a combination of units, or plant aggregate model(s). g. In Ontario we face resistance when our standards exceed NERC requirements. Would it be possible for the SDT in its response to offer its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, if none of our comments can be adopted into the standard, we would appreciate responses such as: "In the opinion of the SDT, having more applicable units on closed loop voltage control, reducing the time to transmit verified information to the Transmission Planner, having specific excitation performance requirements, expanding verified information to include limiters and other devices that affect excitation system performance, and making the requirements in this

standard applicable to wider range of equipment are all practices that will tend to improve reliability." or "In the opinion of the SDT, the requirements in this standard are not intended to preclude continuing or implementing more stringent Transmission Planner requirements" This type of response would help us to continue to augment continent-wide standards with additional requirements to maintain reliability in our part of the interconnection. h. We appreciate the SDT's effort to implement our proposed language changes to remove a potential conflict with the Ontario regulatory practice respecting the effective date of implementing approved standards. The added language, unfortunately, was not added at the appropriate places. We suggest the SDT to move the wording ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," in Section 5.1 to right after "approved by applicable regulatory approval", and move that same wording to right after "following applicable regulatory approval" in Sections 5.2 to 5.4. Also, the same phrase should be appended to each of the four bullets in the Section "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after "following applicable regulatory approval."
Group
Southern Company
Shammara Hasty
No
We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
Yes
Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. Sub-requirement 2.1.4 Is not clear – is this data the model block diagram and its parameters? If so, simply state that. SCS agrees with the modifications to the Periodicity Table as they both simplify and clarify the periodicity.
Group
FirstEnergy
Larry Raczkowski
Yes
Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 7 should be a part of Applicability section 4.2 Facilities. The reader of the standard shouldn't have to get to the last row of an attachment to determine as to whether a unit is exempt or not.
Yes
1. Although we agree with the footnote definition for "technical justification", we would like the term "match" be replaced with "simulates or represents". We feel that these terms give more interpretation when comparing. 2. While we agree that a threshold for unit verification is appropriate, we are not clear as to why there would be different threshold for each Interconnection. The SDT should include a Guidelines and Technical Basis section that explains the geographical differences.
1. FE believes that Requirement 6 in an un-necessary requirement that the Transmission Planner must respond within 90 calendar days that the model is usable. The Transmission Planner should only respond if the information is not usable. We suggest that this requirement should be in a negative perspective and offer the following revision: R6. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 6.1 through 6.5), and shall include a technical description if the model is not usable that includes (but not limited to) the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 6.1. The excitation control system or plant volt/var control function model fails to initialize during a dynamic simulation along with suggested areas for investigation, 6.2. A listing of parameters that fail the Transmission Planner's data checks, 6.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 6.4. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria. 6.5. The excitation control system or plant volt/var control function model submitted by the Generator Owner is either a user defined model or a model that is not acceptable for use in the Transmission Planner's Regional Reliability Organization footprint. 2. For clarity, Requirements 3 and 5 are confusing and seems to be the same. We feel the that R5 can be removed from MOD-

026. This will also be consistent with the requirements of MOD-027.
Individual
Patrick Brown
Essential Power, LLC
1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. 7. Sub-requirement 2.1.4 is not clear – is this data the model block diagram and its parameters? If so, simply state that. 8. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. 9. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.

Individual
Wryan Feil
Northeast Utilities
Yes
Yes
No Comment
Individual
Brian Evans-Mongeon
Utility Services
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Dominion
Mike Garton
Yes
Yes
Dominion agrees with this change; however, is concerned with the phrase "demonstrating that the simulated unit or plant response does not match the measured unit or plant response." The use of the word "match" implies that the simulated response and measures response must be exact, when in fact this will not likely be the case. This language in section 4.2.4 (and other sections) should allow for acceptable variation so compliance can be properly achieved and demonstrated.
Individual
Mike Hirst
Cogentrix Energy
No
We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
No
The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.
1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and

the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage stepresponse tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules Page 5 of 11 up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 6. 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. 7. Sub-requirement 2.1.4 is not clear – is this data the model block diagram and its parameters? If so, simply state that. 8. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. 9. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
Individual
Daniel Duff
Liberty Electric Power
Agree
NAGF
Group
Florida Municipal Power Agency
Frank Gaffney

Related to our comment on MOD-025, if synchronous condensers are only owned by TOs, then the excitation system of a synchronous condenser would not be verified in MOD-026 because it is only applicable to GOs. FMPA recommends that synchronous condenser excitation systems should be verified through the same process, and as a result, if a synchronous condenser is owned by a TO, then a TO should have applicability to it only for excitation systems on synchronous condensers it may own.
Group
Duke Energy
Greg Rowland
Yes
We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units is independent of the physical location.
Yes
Typo - In the Effective Date section 5.3, strike the word “thirty” after the word “quarter” in the fourth line in the clean version.
Group
MEAG Power
E Scott Miller
Agree
Southern CompanyServices, Inc. - Gen
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Individual
Maggy Powell
Exelon Corporation and its affiliates
Yes
No
Applicability Section 4.2.4 currently states "A technically justified2 unit that meets NERC registry criteria and is requested by the Transmission Planner." With the reference footnote stating "Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response." This intended applicability is confusing and implies that the Transmission Planner has the discretion to decide applicability if a previously exempted unit does not meet Transmission Planner decided criteria. Exelon suggests that this be deleted in its entirety. If the GVSDT intent is to pull in other generating units below the MVA threshold criteria based on Transmission Planner discretion, then that should be factored into Applicability Sections 4.2.1 through 4.2.3. In addition, if Section 4.2.4 is also written to negate an exemption based on Transmission Planner discretion then that provision should be factored into Attachment 1 and not into the applicability section.
Exelon again reiterates that the Standard should specifically define the acceptance criteria. The current draft (draft 4) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not “usable”, if there are technical concerns with the verification documentation, or if the model response did not match the recorded response to a transmission system event. This written response is to contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification. It appears from previous comments of the GVSDT that the Generator Owner has final say on the model and the GVSDT has previously responded "that the standard is written so that the Generator Owner “owns’ the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model’s predicted response.”

While Exelon agrees with this statement; Exelon again requests that this language be clearly articulated within the body of the Standard or that definitive acceptance criteria be added to the Standard.
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power System Planning agrees with the revisions made to Attachment 1. Idaho Power Generator Owner- Suggest that "commissioning date" due date requirements be changed to "commercial operation date" to be consistent with other standards.
Yes
Idaho Power System Planning agrees with the revisions made in Section 4.2.4. Idaho Power Generator Owner- The phrase "units that meet the NERC Registry Criteria" has no meaning, since entities and not units are placed on the NERC registry. In addition, demonstrating that a simulated response does not match a measured response is not sufficient technical justification. Additional, technical justification should include demonstration that the different response materially impacts system studes. Additionally, allowing only one year for submission of test results following a technical justification is unreasonable, 5 or 10 years to match the initial implementation time period is more reasonable from the Generator Owner perspective for appropriately planning and scheduling the outage time and work.
1) Technical Justification of units based solely on a simulated response not matching recorded response is insufficient. Technical Jusitification needs to include evidence that the difference in response has a material effect on the conclusions of the relevant system studies. 2) Requiring each Transmission Planner to maintain a list of acceptable models, and then requiring Generator Owners to submit data according to those models is unreasonable. The list of acceptable models needs to be at least regional, if not continent-wide. In addition, some required longevity needs to be specified to allow Generator Owners to appropriately plan and perform the verification work.
Individual
Daniela Hammons
CenterPoint Energy
In R6, CenterPoint Energy recommends changing 90 days to 180 days for a Transmission Planner to notify the Generator Owner that a model is usable or is not usable. Such a change will allow time for model verification through the various regional processes for generator data submittals and dynamic planning case building.
Individual
Kirit Shah
Ameren
No
There appears to be a discrepancy between the language in the requirement R4 and its VSL compared to Row 3 of the Attachment 1. In the both requirement and VSL, a 180 day period is stated, while in Row 3 of Attachment 1, a 365 day period is stated.
Yes
(1)We request that papers listed in the references section of the standard are made readily available on the NERC website. (2)There appears to be an extra word “thirty” in both redline and clean versions of the standard under section 5.3 of the Effective Date section of the draft standard. (3)As we understand, part of R1 is for the Transmission Planner to provide instructions on how to obtain the list of acceptable model types for use in dynamic simulations. In this regard, we ask the SDT if this would preclude the use of user-written models? (4)We still have serious concerns about compliance with new MOD-026-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect. We appreciate the SDT considering our comments on this issue in the last draft, but we still disagree about the potential conflicts for the following reasons: (a)The reporting requirements to comply with MOD-012 are dependent upon the data requirements and reporting procedures put in place by their Regional Entity as mandated by MOD-013. This does not provide consistency across the country. (b)We take data reporting under MOD-012 very seriously and incorporate testing in our program to ensure the data is accurate. Consequently, our reporting and compliance with MOD-012 does involve generator testing on a 5 year basis. (c)Any GO that has implemented a MOD-012 compliance program that involves testing that cannot perfectly synchronize with the 10 year testing in this draft of MOD-026 will have a significant burden in scheduling generator testing to satisfy both standards. (5)We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal

requirements within MOD-026. This will synchronize the reporting and verification requirements and help minimize the resource burden of compliance with both efforts. At the same time it will create consistency across the country.
Individual
Teresa Czyz
Georgia Transmission Corporation
Yes
Yes
Group
Luminant
Brenda Hampton
Yes
Yes
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 2 provides guidance for early compliance and we agree that early compliance should be allowable. It establishes that 10 year period begins from the transmittal date. If a GO has data that satisfies the early compliance condition for a verified model and that data is a five years old, the Note would appear to allow the GO to transmit the data to the TP and receive credit for next 10 years effectively creating an initial 15-year re-verification cycle. Is this intended? If not, please provide more guidance for how soon the GO would have to re-verify its model. (2) Row 3 in Attachment 1 states that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new excitation or plant volt/var control system. However, Requirement R4 also applies to changes to the controls systems. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. (3) Per Requirement R4 and Row 5 in Attachment 1 the GO has 180 days to submit a plan to Transmission Planner to verify the model and then another 365 days to perform the model verification date. That would appear to give the GO approximately a year and half to complete the verification for changes (including replacement) to the control system. Requirement R2 and Row 3 appear to require completion of the verification in 365 days or a year. Please modify the table or requirement to clarify appropriate application.
No
Because NERC and the Regional Entities do not maintain a public list of units that meet the "NERC registry criteria," it is impossible for the Transmission Planner to know for which set of units it may submit a technical justification per R5 and applicability section 4.2.4. The NERC ROP Appendix 5B, Statement of Compliance Registry criteria III.c.1, III.c.2 and III.c.3 each represent fairly "bright lines," where the TP can deduce which units meet these criteria. However, criterion III.c.4 is amorphous and notes on the page 11 of the document give NERC flexibility to deviate from the criteria anyway. Thus, we request that the drafting team either clarify that the "NERC registry criteria" in applicability section 4.2.4 is intended to mean criteria III.c.1, III.c.2 and III.c.3 in section III(c) of Appendix 5B – Statement of Compliance Registry Criteria or that the SDT work with NERC staff to determine how the TP may get a list of units that meet criterion III.c.4 and Note 1.
(1) Thank you for modifying the applicability section. It is greatly improved and is much clearer than the previous version. However, we believe there are a few additional minor refinements necessary. First, generators can be and are part of the Bulk Electric System. Thus, we suggest changing "Facilities that are directly connected to the Bulk Electric System (BES)" to "generation Facilities that are part of the Bulk Electric System." Otherwise, there might be some confusion if the drafting team intends to draw in generators that are not part of the BES. Second, we find the wording "will be collectively referred as an 'applicable unit' that meet the following" confusing. We think the intent was to clarify that an applicable unit is one that is part of the BES and meets criteria established in section 4.2.1, 4.2.2, 4.2.3, and 4.2.4. However, we think the inclusion of the "will be collectively referred as an 'applicable unit'" is superfluous. Because the section is the applicability section, we think this language could be struck for

clarity and the applicable units will be understood to mean those that meet the criteria in section 4.2. As an alternative, the drafting team could explain in a footnote what they mean by the term applicable unit. Third, with the two proposed changes, we think the final wording of section 4.2 after the opening clause should be "generation Facilities that are part of the Bulk Electric System (BES) that meet the following criteria:". (2) In requirement R2, please change "for each applicable unit" to "for each of its applicable units." This is the previous wording and is more correct. The current wording literally says that the GO must provide a verified model for each applicable unit including those it does not own. After all any unit that meets applicability criteria including those owned by other GOs would be an applicable unit. (3) Please specify in M1 that a Transmission Planner may also provide an attestation that no such request was received if this is the case. Use of attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set in the use of attestations in measures in FAC-003-2 M1 and M2. (4) We continue to believe that the examples provided in the comment form should be included in the standard. Please create an Application Guidelines or Guidelines and Technical Basis section in the standard and add them. This has become common practice with developing standards. We do not understand why the drafting team would not want to retain such information that helps readers understand the standard and that has already been developed. Furthermore, it would make it easier for commenters to see what has changed in the examples because a red-line of the standard is required. Because the examples were contained in the comment form this time and during the previous posting, it is not easy to deduce the changes because there is no red-line. If the examples are not included in the standard, please provide more explanation than was provided during the last response to comments which was that it is not appropriate to include the examples. We do not understand why it is not appropriate. (5) We disagree with the need to retain the latest model verification evidence under Requirement R2 and M2. First, this is not consistent with the Section 3.1.4.2 of Appendix 3c to the NERC Rules of Procedure section which states that the audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since the audit cycle for a GO is six years and the model verification period is 10 years, the GO will have to retain data past its prior audit period. Furthermore, the auditor will have already had an opportunity to review the model verification data during the last audit. Presumably, if they did not find any compliance violations, there should not be a need to review this data again. Thus, the data retention should not exceed the six year audit cycle. (6) How will mothballed units be handled in Attachment 1? If a mothballed unit is returned to service which row in Attachment 1 applies? What if the unit was mothballed before the effective date and returned to service after all stages of the effective dates? What if it was mothballed after an initial verification? How does this affect the next verification date?
Individual
Don Jones
Texas Reliability Entity
Yes
As TRE stated in previous comment periods to the standard, we disagree with using the 5% capacity factor (Attachment 1, Row 7) to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. We recognize this is somewhat alleviated by Requirement R5, which now provides a method for the TP to request a model verification for a unit that has less than 5% net capacity factor if the unit's simulated response fails to match its measured response.
Yes
Should Blackstart units have a specific inclusion as an "applicable unit", regardless of capacity factor or "technical justification"?
1) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. 2) TRE recommends changing to "Planning Authority or Transmission Planner" in the Functional Entities in Section 4.1.2 instead of "Transmission Planner". This change should be duplicated in the requirements. The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. 3) The timelines are generally too long, which will result in stale, incorrect and generic data being utilized in modeling systems. Consider shortening timeframes.
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No comment on this question
No

No comment on this question.
A stated purpose of Generator Verification is “to ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.” Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets’ capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load’s process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load’s produc tion schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Russell Noble
Cowlitz PUD
No
Cowlitz supports the comments put together by the NAGF SRT: 1. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. 2. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
No
Cowlitz is unsure if it is possible to accurately model generation such that modeling software will be able to predict actual plant response to a disturbance. The Standard may create a never ending circle of requests from the TP for improved modeling data. Cowlitz understands that modeling software is still in its infancy, and more research and testing is needed to explore the boundaries between achievable modeling and where unrealistic goals exist.
Cowlitz supports the comments put together by the NAGF SRT: 1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC’s March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage stepresponse tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition

of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 6. 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. 7. Sub-requirement 2.1.4 is not clear – is this data the model block diagram and its parameters? If so, simply state that.
Individual
Don Schmit
Nebraska Public Power District
Agree
MRO NSRF

Kathleen Goodman
ISO-New England
No
Row 3 requires model transmittal "within 365 calendar days after commissioning the unit". It is not acceptable in terms of system reliability for a large unit to be operating on the system for 365 days after commissioning without a verified model. FERC approved ISO Tariff language also calls for provision of the model prior to Commercial Operation. The standard would not meet the requirements of the Tariff. Row 7 discusses capacity factor. The capacity factor reference has been removed from the requirements. If the capacity factor is still to be used this is unacceptable from a reliability standpoint. Large generators that have a low capacity factor will be required to operate under extreme conditions when the system is most stressed. A verified model should be provided regardless of capacity factor given this consideration.
Kathleen Goodman
ISO-New England
No
This means that the Transmission Planner can only call for verification following a system event. It is counter to reliability to have to wait for an event to occur to then request verification. The footnote should be revised to include wording for the Transmission Planner to demonstrate an effect on the BES. Certain generators under 100 MVA could affect the BES and with this language verification could then take place.
Kathleen Goodman
ISO-New England
Requirement R1 may bring out some concern over the copyrighted models supplied by the simulation software

vendors. Hopefully this can be worked out with the vendors.

Requirement R2.1.3 should indicate the requirement for the total combined turbine/generator inertia constant. Simulations need to study the combined inertia of the turbine and generator not just the generator.
A requirement R2.1.7 should be added to require verification of generator excitation limiter settings.

A requirement R2.1.8 should be added to require verification of supplementary voltage control inputs.

Requirement R3 only requires a "written response" from a Generator Owner to the Transmission Planners notification that a model is not useable. Wording must be included so that ultimately the Generator Owner shall provide a "usable model" to the Transmission Planner.

Requirement R4 must be modified so that models are provided prior to making changes in the excitation control system or plant volt/var control function. It is counter to system reliability to allow generators to modify and subsequently operate equipment without notifying the Transmission Planner.

Footnote 6 should be modified to include ability for the Transmission Planner to require a verified model from a generator under the size threshold if the generator impacts the BES.

Requirement R6 sub-requirement wording should be changed to indicate the Transmission Planner shall notify the Generator Owner if the excitation model does not initialize, a no-disturbance simulation results in transients or a disturbance simulation results in a model exhibiting negative damping.

Individual or group. (54 Responses)
Name (35 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (8 Responses)
Comments (54 Responses)
Question 1 (30 Responses)
Question 1 Comments (46 Responses)
Question 2 (38 Responses)
Question 2 Comments (46 Responses)
Question 3 (0 Responses)
Question 3 Comments (46 Responses)

Individual
Brian Bejcek
Yes
Yes
I would recommend that the standard applicability be narrowed to BES units only. The way I read the standard draft it would apply to all generating units. This seems to be a significant cost and amount of work for smaller units that will not have a great impact on the BES. I would suggest that in the applicability section of the standard that the BES unit definitions be used (greater than 85MVA, connected >100kV, etc).
Individual
Jim Watson
Yes
No
R4 requires the GO to provide the Transmission Planner an estimate of the time duration a generator will stay on during a frequency or voltage excursion. It appears this question would already be answered in complying with R2 when the GO verifies the relay settings against the graphs in Attachment 2. It's also not clear whether R4 is to be accomplished before or after a request from the Transmission Planner. It is recommended R4 be removed. If it is not removed, add "…if requested." at the end of the first sentence.
This Standard is similar to the PRC-006-NPCC-1 and PRC-006-SERC-01 Automatic Underfrequency Load Shedding Standards. PRC-024-1 requires continuous operation at >59.5 Hz. PRC-006-NPCC-1 requires continuous operation at >59.0 Hz. This is confusing. These three Standards should be coordinated or the GO applicability should be removed from PRC-006-NPCC-1 and PRC-006-SERC-01.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with

other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. Regarding the Table for the Quebec Interconnection in Attachment 1, the data should read: High Frequency Duration Frequency (Hz) Time (Sec) Greater than 66.0 Instantanous Trip Greater than 63.0 5 Greater than 61.5 90 Greater than 60.6 660 Less than or equal to 60.6 Continuous Operation Low Frequency Duration Frequency (Hz) Time (Sec) Less than 55.5 Instantaneous Trip Less than 56.5 0.35 Less than 57.0 2 Less than 57.5 10 Less than 58.5 90 Less than 59.4 660 Greater than or equal to 59.4 Continuous Operation Wind generation is included in the table as has been previously confirmed with the Drafting Team.
Group
Pepco Holdings Inc
David Thorne
Yes
Yes
A footnote 2 reference to qualify the term “existing generating unit” should also be included in the last bullet in Requirement R2. Also, the language in footnote 2 should begin with “Includes …” rather than “To include…”
Individual
Cristina Papuc
Yes
Yes
The UFLS curves for Eastern Interconnection and Quebec Interconnection are different from those curves on NPCC Directory 12. Which one to be compliant?
Individual
Nazra Gladu
Yes
None.
Yes
Manitoba Hydro noticed that the “clean” and “redline” versions of the standard are inconsistent. Both 4.1. and 4.2. should be removed from the “redline” version since both are redundant (included in the text of R4.).
VSLs - The VSLs for R1, R2 and R5 have been omitted for both Low, Moderate and High. Is there any rationale for this omission? Attachment 1 - Attachment 1 in MOD-026 and MOD-027 assist in adding clarity to the periodicity of exciter and turbine/governor model testing. These attachments also allow low capacity factor units and equivalent units connected at the same location to not be tested every 10 years, which is prudent. Manitoba Hydro would like the drafting team to consider whether conditions in row numbers 1-5 and 7 in attachment 1 of MOD-026 could also be applied to standards PRC-019, MOD-025 and possibly PRC-024. R1 and R2 - The requirement speaks about the ‘unit’ tripping but the sub requirements speak about the ‘Generation’ tripping – is this not inconsistent? R1 and R2 - 1. The language in R2 currently reads, “Each Generator Owner that has generator voltage protective relaying activated to trip its generating unit shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2 or within the voltage recovery characteristics of a location-specific Transmission Planner’s study if the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2 subject to the following exceptions”. Manitoba Hydro made the following comment to draft 3 of PRC-024-1 during /29/12-03/29/12 commenting period, “R1 - the facility interconnection document required through FAC-001 should supersede Attachment 1 in order to best address local area issues. R1 should be revised to specify this.” The drafting team responded, “The SDT was charged with creating continent-wide requirements for frequency and voltage excursions and believes that consistency will not occur if various Transmission Service Providers apply various “no trip zones.” Requirement R1, therefore, should not be dictated by FAC-001.” Even though the drafting stated that other standards (eg. FAC-001) shouldn’t set continent wide settings, the drafting team has permitted less stringent voltage relay settings in R2 as long as it is accompanied by a Transmission Planning study. Manitoba Hydro understands that continent wide-standards are preferred but there should be flexibility for local area considerations as has been done in R2. Manitoba Hydro requests the drafting team consider the following language added to R1: …or within the frequency recovery characteristics of a location-specific Transmission Planner’s study

if the Transmission Planner allows different (more or less stringent) frequency relay settings than those required to meet PRC-024 Attachment 1… And the following modification to R2: …or within the voltage recovery characteristics of a location-specific Transmission Planner's study if the Transmission Planner allows different (more or less stringent) voltage relay settings than those required to meet PRC-024 Attachment 2… 2. The drafting team has removed the following exception in R1, "A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec." What is the technical basis for removing this exception? Is the intent that no tripping in the "no trip zone" is permitted regardless of the potential rate of change of frequency? There were no comments on this item in the last draft. R2 - The first bullet has a typo – 'tripping' should be changed to 'trip'. R3 - This requirement requires that Generator Owners document each 'known' equipment limitation. The word 'known' can be legally ambiguous - known to whom? actual knowledge or 'should have known', 'could have known'? R5 - The text of footnote 5 has been deleted, but the footnote remains. General Comments: 1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? 2. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled "Consideration for early Compliance" with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1).
Individual
Carter B. Edge
Yes
Yes
An additional "may trip" exclusion is needed for R1 and R2 related to properly set V/Hz relaying. Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Note: Depending on approval dates, R6 may repeat requirements that are being developed in revisions to PRC-001 and/or PRC-027. Not really protection related: The additional costs involved for re-designing generating stations under R5 so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability of a voltage and/or frequency excursion occurring. It is inappropriate to support approval of such a requirement until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved.
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
Group
pacificorp
ryan millard
Yes
Yes
Individual
Winnie Holden
Yes
Yes

This FIRST comment was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1. 1.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1, R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all "modelers," the result will be outdated data in someone's model, which can have a bad result. The team should have one broad "data sharing" policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: "The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it." 2.We do NOT believe that R5, which sets requirements for new generators (including balance-of-plant equipment) to the requirements in Attachment 1 and Attachment 2, has been appropriately vetted by the SDT. Many stakeholders are unfamiliar with the performance capability of new generators, including the cost of achieving the performance requirements in R5. Therefore, the SDT should develop additional expert information to confirm that the requirements in R5 represent the norm for new generation. We suggest that the SDT reach out to the NERC Planning Committee, who in turn may research this topic with the IEEE and the North American Generator Forum and develop a report on their findings. With all due respect to the SDT, until stakeholders have independent confirmation regarding R5, it will be difficult for them to accept it.
Individual
Alice Ireland
Yes
Yes
Xcel Energy would like to point out that the high frequency duration curves for the Eastern, ERCOT, and Quebec Interconnections exceed the allowable short-term frequencies specified in IEEE C50.13 and IEC 60034 which the OEM's use to design their generators. Attachment 1 should be modified to meet the IEEE and IEC standards. Also, Xcel Energy continues to believe that Requirement R5 would result in a large cost increase in the cost of building new generating units which would defer resources that could be better used elsewhere to improve grid reliability. Xcel recommends that this requirement be revised such that if a generating unit did trip during a voltage or frequency excursion, the Generator Owner investigate the cause and develop a corrective action plan to address the trip.
Individual
Michelle R. D'Antuono
Yes
No
Unlike MOD-026-1, which requires some amount of justification from the requesting entity before action must be taken, PRC-024-1 R4 requires compliance without any regard to the Generator Owner's resource availability. In general, Ingleside Cogeneration LP believes that a good working relationship between the Generator Owner and Transmission Planner includes a reasonable justification for any request that requires time and expense on the part of the other.
Ingleside Cogeneration LP agrees that Transmission Planners and other operating entities must be able to rely on a generator's availability when voltage and frequency transients occur at the interconnection point. However, we are not convinced that the project teams assertion that all technologies can accommodate the ride-through thresholds posed in PRC-024-1 R5 simply because some European nations already require them. This trivializes a major concern that a generator and all its auxiliary systems must remain online while severe stress is imposed upon mechanical systems spinning at high speeds. Our vendors are telling us that they don't know if they can accommodate the specified thresholds – and they have decades of engineering experience behind their assessments. In addition, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements that look for evidence that a unit does not trip in response to a transient (R5) must contain language that focuses on the strength of the process – not the actual performance. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will automatically assess a violation regardless of whether the trip was necessary to protect equipment or safety. The CEA's focus

needs to be on the entity's commitment to establishing the necessary ride-through settings over the longer term. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects.
Individual
Andrew Z. Pusztai
Yes
Yes
In Requirement 3.1 – ATC recommends replacing the wording of "shall communicate the documented equipment limitiation" with "shall communicate the documented equipment limitiation and the expected duration of the limitation, if it is known". The addition of expected limitation duration could be valuable reliability information.
Individual
Anthony Jablonski
ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: VSL Requirement R5 – ReliabilityFirst still believes the VSL for Requirement R5 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R5 states "Each Generator Owner shall design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion." The VSL states "The Generator Owner's generator tripped due to a Frequency Excursion within the no-trip parameters set forth in attachment 1". Based on the FERC Guideline #3, the language in the requirement is not consistent with the associated VSL. It is not a violation of Requirement R5 if the generator tripped offline within the no-trip parameters, rather it is a violation if the GO failed to design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion within the no-trip parameters set forth in Attachment 1. Furthermore the SDT noted in the response to comments that the VSL relates to Measure M5. ReliabilityFirst would like to remind the SDT that based on the NERC definition of VSL (as noted in the NERC Standard Processes Manual), "VSLs define the degree to which compliance with a Requirement was not achieved." There is no mention of VSLs being written based on the measurement of the requirement. ReliabilityFirst recommends either modifying the requirement or VSL so they both use consistent language.
Individual
Thad Ness
No
R4 should be removed entirely from this standard. R4 appears to add no reliability benefit beyond what is already prescribed in R3. Documentation of equipment limitations as possible causes for tripping within the no-trip zones of Attachments 1 and 2 will allow PCs and other entities to check for instances where UFLS effectiveness or system voltage recovery might be compromised by possible early tripping of generators due to factors other than relay settings.As these benefits seem to be the intent of R3, R4 does not appear to add any useful information beyond what would already be supplied under R3. We further expect that GOs will be unable to devise the required estimates of time duration without detailed simulations of generating unit and auxiliary system performance (the explicit statement that detailed studies are not required notwithstanding) during the specified frequency or voltage excursion profilesto be supplied to them. Were these intended to be trajectories rather than profiles?
1) R1: Should R2, first bullet point exception have a similar counterpart in R1? 2) R2: Does footnote 2 also apply to R2 fourth bullet point? 3) R3: On the last bullet we suggest the word "nameplate" be removed from the sentence. 4) R5: AEP believes that the requirement of R5 for new units and plants to not trip within the no-trip zone of Attachment 1 is reasonable, and has precedence in existing reliability region guidelines. To not trip within the no-trip zone of the Attachment 2 is another matter. AEP maintains that Attachment 2 is inappropriate as a requirement on new conventional generation. When AEP previously raised objection to the reference to

Attachment 2 by R5, the SDT replied: "The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain." We note that Order 693, paragraph 1787 does require generation to ride through B and C contingencies. However (and we reference the Consideration of Issues and Directives table associated with PRC-024), Order 661 was superceded by 661-A which removed the voltage ride-through curves of the sort as Attachment 2. The SDT is justifying the imposition of an unprecedented (in North America) and onerous requirement on the basis of outdated information. Moreover, the SAR for Project 2007-09 was a general authorization to proceed with standard development on the subject of generator performance during frequency and voltage excursions, not an authorization to require the specific voltage-ride through requirement for new generation now proposed in R5. Please reconsider the justification for this requirement. The SDT further replied: "If the Transmission Planner for a new generation facility can provide the voltage profile for that specific site, then per Part 5.2 the Generator Owner can design his new facility to ride through that profile even if it is less stringent (i.e. uses faster clearing and faster voltage recovery) than Attachment 2. The voltage envelope described in Attachment 2 provides equipment OEM's with an outer boundary on the voltage stress they have to design for." The exception enabled by the second bullet point of R5 may cause a nonuniform level of reliability. If one transmission planner presents a less stringent voltage ride-through characteristic (we assume this would be simulation based--R2, Part 2.2 does not exist) to a potential generator than the TP next door, who for lack of time or resources falls back on Attachment 2, then at best, a nonuniform level of reliability would result. Shouldn't there be some uniformity on what generating units are obligated to acheive? We mention this point, not that the exception be removed, but that the requirement of Attachment 2 for new generation, which has not been seen as necessary for reliability in the past, be removed. The SDT further replied to our concern over cost to comply: "There are similar voltage ride through requirements already in effect in parts of Europe and Asia. The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT agrees that generating units designed and built to meet Requirement R5 will be more costly than those that cannot meet this reliability goal. The SDT is not in a position to place a monetary value on the consequent reliability gain. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain." The SDT is in error in thinking that the reference to Attachment 2 in R5 is necessary to implement Order 693 or to fulfill the intent of the SAR as noted above. We also question the propriety of adding a new reliability standard requirement without precedent in North America irrespective of any consideration of the cost to comply, and a proposed requirement that will certainly act to disfavor new conventional generation compared to what has always been accepted design practice for conventional generation in the past. The SDT needs to provide a relevent technical argument for the new level of reliability and not an appeal to what other parts of the world may be doing. 5) If R5 remains in this standard, its associated measure needs to be changed so that evidence would need to be provided for only those unit trips that occurred during a voltage or frequency excursion. As currently written, evidence would need to be provided for every unit trip, which is both unnecessary and unduly burdensome. 6) R6: As currently drafted, all requests would require continual updates unless otherwise exempted. This should be changed so that all requested are treated as a onetime request unless otherwise specified by the requesting entity.
Individual
Dale Fredrickson
Yes
No
We maintain that there is no reliability driven need for R4. Also, such estimates would be of limited accuracy. Should such an estimate be deemed useful, it can be requested informally among the appropriate entities. Standards and associated requirements must be reserved for those items more critical to BES reliability
1. In R2, it is not specified whether the voltage ride-through curve (Attachment 2) refers to three-phase voltages or any one phase. This makes an enormous difference in the ability of equipment to withstand the sag. More importantly, the extreme voltage ride through requirements do not appear to be technically feasible to achieve for coal and gas-fired turbine-generators. The voltage ride-through requirements should be re-examined to verify they are justified by reliability need, and separated from the more critical frequency coordination requirements. We believe that a separate standard is needed for the voltage requirements, which are not as clearly justified or supported by existing equipment. 2. R2 consists of a single sentence with over 100 words. This needs to be corrected. 3. In R3 and associated M3, the GO is responsible to document equipment limitations that prevent the unit from meeting the frequency and voltage performance curves. However, it is not uncommon for the generating unit to experience problems in a wide variey of plant systems which result in unit trips. Thus the GO is not necessarily aware of the source of these less frequent unit trips caused by external events, such as transmission system faults, and associated voltage sags. Therefore this requirement needs to also apply to the Transmission Owner. The TO (or TP) should be required to identify those events within its system that may have adversely affected generating units. Only then can the GO be responsible to identity its equipment limitations. Without this joint responsibility, this requirement should be removed. 4. In R3.1, the requirement is for the GO to communicate

equipment limitations to four different entities. This requirement is in the long-term planning horizon, and therefore the communication should be limited to the TP only, and not the other entities. The TP is the primary recipient, and they can pass the information to the other entities as necessary, as described in the NERC Functional Model. In addition, the time requirement of 30 days is unreasonably short; we suggest that 90 days would be sufficient for this long-term planning requirement. 5. In R5, it does not appear that new thermal plants can meet these requirements, which have largely been developed for wind farms, especially Attachment 2. The auxiliary systems of such plants cannot be quaranteed to meet the performance curves, apart from a strong cooperative effort by equipment suppliers to design these requirements into the equipment. There need to be industry standards (e.g., IEEE) in place before this requirement is ready for industry use, such as performance standards for equipment like variable-speed drives, for one example.
Individual
Michael Falvo
Yes
Yes
1. We appreciate the SDT's effort in making clarifying changes to the Implementation Plan to separate the effective dates for jurisdictions where regulatory is and isn't required. And we understand that the phrase "following applicable regulatory authority" includes regulatory bodies from Canadian provinces requiring regulatory body approval. However, the separation alone and leaving the phrase "following applicable regulatory authority" unchanged do not address the situation in Ontario where (a) regulatory approval is required" but (b) the effective dates are not necessarily tied with the effective dates indicated in the Sub-Section that applies to those jurisdictions where regulatory is required.In other words, the proposed languageonly partially reflects Canadian regulatory framework and we suggest additional wording, as described below. We request the following phrase be added to each sentence under the "In those jurisdictions where regulatory approval is required" of the Implementation Plan: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." right after "following applicable regulatory approval". The revised first bullet, for example, will read: • By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6. And the same change to each of the sentences in Section A5.1 of the standard should also be made. 2. The impact of disconnecting a generating unit less than 20 MVA or a generation plant less than 75 MVA during frequency or voltage excursions is very limited. We suggest to add the following facility thresholds into the applicability section: a. Generating unit with a gross nameplate rating greater than 20 MVA b. Generating plant with an aggregated gross nameplate rating greater than 75 MVA 3. There is a typo on the R2 footnote on "protective relaying". It should be 2 instead of 1.
Group
Tennessee Valley Authority
Brandy Spraker
No
Recommend that the R4 be enhanced to give more detail on how to satisfy this requirement. As significant as R4 is, the Generator Owners need more guidance than what is currently stated.
1. The technical justification for the need of a plant performance criteria appears to be based on issues with early design wind generation. The technical considerations at these types of generation stations are different than steam turbine generation plants, which require heavy induction loads to support operation and these loads are sensitive to upsets in voltage and frequency. The technical implications of the plant performance are not clear. Recommend generating a separate SAR and bring in industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical acadamia, etc. to assist in the technical analysis and standard development. 2. Likewise, industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical acadamia, etc. can develop acceptable methods to determine the capability of a plant to ride through grid transients. 3. The following are IEEE Electric Machines Committee comments for PRC-024-1 consideration The IEEE Electric Machinery Committee hosted a discussion topic on "Grid Code Impact on Electric Machine Design" in San Diego at this year's Power Engineering Society meeting and offers the following input. • Minor changes in the Under-frequency Ride Through Curve are suggested to better match existing machine design standards in IEEE C50????. • The PRC-024 Voltage Ride Through criteria is technically not ready to be a standard, for the following reasons; 1. PRC-024 VR capability may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. It is believed the cost of complying with wider standards might increase main generator machine costs as much as 25%, which is not insignificant.

This should only be required if there is a defined local system need for higher standards and that these costs should be considered against the cost of other possible resolutions. 2. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of all 4160V and 460V systems in new plant can be dynamically modeled to a degree allowing one to obtain non-drop-out guarantees from equipment suppliers and EPC firms for extreme transients such as 2.0 seconds at 65% voltage, or that the same can be done for existing plants to allow identification of limiting components and accurate estimates of performance. 3. The voltage ride through was originally intended to address early deficiencies in wind generation design only and it doesn't make sense to apply such a broad curve to steam plants. The concerns that led to the VRT curve for wind have been addressed by new vintage wind plant designs and thus, the EMC does not believe there is not driving need for a standard VRT criteria. • The VRT issue is holding up addressing other significant issues addressed by PRC-024 (relay setting coordination and frequency ride through). The VRT should be pulled out of PRC-024 and a new SAR drafted to address the voltage performance aspects if this is really needed for reliability. • More clarity in defining plant MVARs available to support grid voltage is needed. Specifically, generation plants have not been designed to operate outside a normal band of 95 to 105% on the generator terminals. GSU settings are typically chosen to optimize MVAR support under normal operations, however is not reasonable to assume the full leading or lagging reactive support would be available under normal grid conditions.
Group
Southern Company
Shammara Hasty
Yes
Yes
An additional "may trip" exclusion is needed for R1 and R2 related to V/Hz set properly to limit overexcitation of generators or transformers. Please consider a requirement for the TP to perform location-specific system voltage recovery studies referenced in R2. This should be a requirement for the TP prior to requiring the severe voltage profile of Attachment 2. Both the exemption of existing units using the exceptions in R1 and R2 for "documented and communicated equipment limitations" and "the estimation of time a unit will remain connected" per R4 are problematical. Power plants exhibit a tendency for have drum level fluctuations, air/flue gas flow oscillations, or other plant subsystem instability during system disturbances which are not defined in OEM literature. It is generally not possible to determine when such problems will occur especially if a disturbance involves cycling above and below the rated frequency within the Attachment 1 boundaries. The same is true regarding predicting transient fluctuations of auxiliary system bus voltages. These voltage fluctuations affect power distribution equipment in the power plant by contactor or control relay drop-out, major auxiliary equipment stalls, etc. Predicting when a plant trip will occur due to these types of power plant system responses is problematic. The "10% power increase" exemption loss (in the last bullet item of R3.1) may effectively ban entire classes of equipment or prevent units from ever receiving capacity and efficiency enhancements. We object to R5 – the additional costs involved for re-designing generating stations so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability of a voltage and/or frequency excursion occurring. Furthermore, we believe it is fundamentally inappropriate to support approval of such a requirement until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved. We recommend this requirement be removed so the standard can move forward to address the shorter term goals that are achievable. Further commentsi regarding R5: Currently, there exist too many engineering challenges to permit the requirement of R5. These include the following: Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. Auxiliary equipment contactors and energized control relays are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses. This dropout will occur within a few cycles. The basis of compliance for new units is simply, "will not trip," i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting-down the new powerplant industry unless an owner were willing to take unbounded risk. This will require revision of, not only plant equipment standards, but "plant system" standards. Even if we could certify all of the components, you cannot guarantee once they are implemented into a system they will respond as planned. Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-

separate basis of Att. 1 and Att. 2 in this standard. The SDT stated in their previous PRC-024 Consideration of Comments that grid requirements similar to R5 are already in effect in parts of Europe. U.S. standards still prevail for design, construction, and operation of plants in the U.S. We believe it is inappropriate to implement a national standard requiring U.S. plants be designed to the requirements of R5 until the industry can demonstrate through additional research, development, and revision of the plant equipment and system standards that such requirements can be practically met. Please consider requirements for TO to address the frequency and voltage excursions in the transmission system in order to arrest the abnormal condition locally. Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Also , this requirement may repeat requirements that are being developed in revisions to PRC-001. It is inconceivable that most plants can ride through a + or - 10% voltage excursion for 10 minutes per PRC-024, Attachment 2. Almost all would have to take exception. All of our nuclear plants would trip as would the new nuclear plant currently under construction.
Group
Western Electricity Coordinating Coundil
Steve Rueckert
Should part 4.2 read Idntificatoin of the basis rather than Identification of the bases
WECC is concerned that Requirement R3 of PRC-024-1, which requires Generator Owners to document each known equipment limitation that prevents a generating unit from meeting the frequency requirements of Requirement R1 may be in conflict with or less stringent than the requirement in the WECC Off-Nominal Frequency Load Shedding Plan that requires Generator Owners that have generators that do not meet the frequency requirements to automatically trip load to match the anticipated generation loss or have contractual relationships providing for automatic load shedding. The concern is that Generator Owners may interpret Requirement R3 of PRC-024 to relieve them of their obligations under the WECC Coordinated Off-Nominal Load Shedding Plan. This is a concern because the original design and subsequent simulations conducted to validate the effectiveness of the WECC Off-Nominal Frequency Load Shedding Plan reflect simulation of the generator underfrequency and overfrequency operation requirements, and any deviations from these requirements would invalidate the effectiveness studies and could potentially require modifications to the existing approved WECC Coordinated Plan.
Individual
Patrick Brown
1.The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1 are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions that are unsafe. 2.Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. 3.Auxiliary equipment contactors are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses. 4.Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. 5. The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to “protective relaying,” which per footnote #1 in PRC-024 includes “protective functions within control systems…based on frequency or voltage inputs.” It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions. 6.The basis of compliance for new units is simply, “will not trip,” i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting-down the new power plant industry unless an owner were willing to take unbounded risk. 7. A “will not trip” obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. It is noteworthy in this respect that environmental regulators have for decades been pushing gas turbine dry low-NOx combustors to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances. Greater consideration of BES reliability may be needed, but doing so by issuing dueling regulations would not constitute an appropriate approach. 8. M5 causes new-unit tripping due to frequency or voltage excursions within PRC-024 limits to constitute a violation, but it seems unlikely to expect an “or” event. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-separate basis

of Att. 1 and Att. 2 in this standard. 9. The grandfathering of existing units in R1 and R2 for, "documented and communicated equipment limitations," is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations and the like during Disturbances will not be defined in OEM literature, nor is it generally possible to predict by calculations when such problems will occur, especially if a Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true regarding predicting transient fluctuations of aux bus voltages, ref. risk of contactor drop-out and stalling major auxiliary equipment. 10. The concern above applies also to having to make reference per R3 to, "study results, experience from an actual event, or manufacturers advisory." Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1 and Att. 2. The list of types of evidence in R3 is not exclusive, but it is difficult to imagine alternative forms of hard evidence that could be developed other than for the comparatively few plants that possess high-fidelity simulators. 11. The same concerns regarding availability of information apply for the, "estimate of the time duration the existing generation unit will remain connected," in R4. Relying on "sound engineering judgment" is permitted, and R4 states that "detailed unit performance studies are not required;" but the word "sound" implies that the estimate is to be based on accurate data, and how such information could be developed without a detailed study is unclear. 12. Confusion is created by making grandfathering, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such protective relays meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any grandfathering is actually being allowed. 13. The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. 14. Steam turbine off-frequency limits are generally set by OEMs lifetime limits as regards duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated. 15. An additional "may trip" exclusion is needed for R1 and R2 related to V/Hz set properly to limit over excitation of generators or transformers. 16. Objection to R5 – the additional costs involved for re-designing generating stations so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability of a voltage and/or frequency excursion occurring. Furthermore, we believe it is fundamentally inappropriate to support approval of such a requirement until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved. We recommend this requirement be removed so the standard can move forward to address the shorter term goals that are achievable. 17. Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Also, this requirement may repeat requirements that are being developed in revisions to PRC-001. 18. It is inconceivable that most plants can ride through a + or - 10% voltage excursion for 10 minutes per PRC-024, Attachment 2. Almost all would have to take exceptions.
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Individual
Wryan Feil
Yes
Yes
No comment
Individual
Brian Evans-Mongeon
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate

meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Dominion
Mike Garton
Yes
R4.1. and R4.2. are listed in the redline standard, but not in the clean version of the standard.
Individual
Mike Hirst
Project 2007-09 Generator Verification includes draft standard PRC-024, Generator Performance During Frequency and Voltage Excursions. Requirements R3 and R4 are for existing generating units. R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented cases where generator protective relaying cannot be set, and directs those generators to communicate that limitation to the RC, PC, TOP and TP so its performance can be modeled correctly. R4 requires a Generator Owner to estimate the time duration for remaining on-line based on a Transmission Planner's dynamic study. Requirement R5 directs all new generating facilities to be designed, built and maintained so that they are able to ride through the excursions defined in Attachment 1 and 2. Voltage Ride-Through Background In FERC Order 661 (June 2, 2005), Final Rule on Interconnection for Wind Energy, the Commission adopted a low voltage ride-through standard for wind generators, but provided that a wind plant is required to meet the standard only if the Transmission Provider shows, in the System Impact Study, that low voltage ride-through capability is needed to ensure safety or reliability. The standard, if applicable, requires the wind generator to stay online for specified time periods and at associated voltage levels where there is a disturbance on the transmission system. Several entities requested rehearing of various aspects of the low voltage ride-through requirement and standard included in the Final Rule. In FERC Order 661-A (December 12, 2005) page 2, the Commission noted "that the standard interconnection procedures and agreement were based on the needs of traditional generation facilities and that a different approach might be more appropriate for generators relying on other technologies, such as wind plants. Accordingly, the Commission granted certain clarifications, and also added a blank Appendix G to the standard Large Generation Interconnection Agreement (LGIA) for future adoption of requirements specific to other technologies." The Commission went on to adopt in Appendix G to the LGIP limited special interconnection procedures applicable to wind plants only. The basis for the change to the standard regarding voltage ride through starts with FERC Order 693, Paragraph 1787 (March 16, 2007), which states "… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. " Discussion, Voltage Ride-Through Although FERC Order 661-A does make a provision for future adoption of voltage ridethrough requirements for all generators, the Order is careful to differentiate between wind generation technologies and other, traditional generation facilities. No instruction is given for other technologies in the Order. Nowhere in any of the FERC Orders (661, 661A, 693) is there a single requirement for non-wind generators to meet ride-through requirements. Docket No. RM05-4-000 (Order No. 661) discusses this subject directly. The Notice of Proposed Rulemaking (NOPR) Interconnection for Wind Energy and Other Alternative Technologies dated January 24, 2005, sought comments on certain specific issues, including whether there are other non-synchronous technologies, or other technologies in addition to wind, that should also be covered by the proposed Appendix G. In FERC Order No. 661, the Final Rule on Interconnection for Wind Energy, the Commission noted "These technical requirements for the interconnection of wind plants recognize the unique design and operating characteristics of wind plants,1 their increasing size and increasing level of penetration on some transmission systems, and the effects they have on the transmission system." Further, they wrote, "The Final Rule Appendix G we adopt here applies only to the interconnection of wind plants. The Commission does not believe at this time that the standard procedures and technical requirements in this Final Rule are appropriate for other alternative generating technologies that may supply over 20 MW at one Point of Interconnection. The standard procedures and technical requirements adopted here recognize the unique characteristics of wind plants, including the fact that they use induction generators, consist of several or numerous small generators connected to a collector system, and do not respond to grid disturbances in the same manner as large conventional generators." The Final Rule also noted that while low voltage ride-through capability is needed for wind plants, it is less of a concern for large synchronous generating facilities because most of these facilities are equipped with automatic voltage control devices to increase output during low voltage events. The Commission concluded that the Final Rule Appendix G exceptions to the LGIP and 1 As noted above,

wind plants over 20 MW in total size are subject to the standard technical requirements in the Final Rule Appendix G. These wind plants are generally made up of several small induction wind generating turbines, laid out over a large area, and connected through a medium-voltage collector system. This collector system is connected to the low voltage side of the step-up transformer, which is then connected to the transmission system at a single Point of Interconnection. LGIA apply only to large wind plants. Appendix G was designed around the special needs and design characteristics of wind generators. The Appendix G provisions adopted "focuses on the special characteristics of large wind plants, particularly the fact that they utilize many induction generators connected to the transmission system at a single point through a medium-voltage collector system. The Commission has not found at this time that any other technologies, including the solar generators without fueled backup …, have similar characteristics." The Project 2007-09 Generator Verification Standard Drafting Team has presented the current draft of the standard as a technology-neutral version, ignoring the fact that power plant performance in asynchronous vs. synchronous units for transmission excursions are significantly different and are technology dissimilar for reasons of voltage regulation ability and plant auxiliary design. • The NERC System Protection and Control Subcommittee wrote, in previous comments, "FERC 661-A is a wind generator facility ride-through performance criterion, not a synchronous generator relay setting requirement. They cannot be considered as being the same. This requirement in PRC-024 should only apply to non-synchronous machines." • Constellation Power wrote, "The idea of a ride-through curve originated with wind farms, and is not conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines." • PPL Energy commented, "PPL is concerned with the following concepts in the standard: 1) The standard applies equally to asynchronous and synchronous machines, salient pole and round rotor machines, photovoltaic, and other resources and as such the standard does not appear to recognize that these technologies respond differently to voltage and frequency excursions." • AEP posited "The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied." • Pacificorp offered "Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms." Furthermore, OEM's have not yet developed a solution to voltage ride through for nonwind generators. Assured compliance with PRC-024 may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. Regulation should not come before a solution is available. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of medium and low voltage auxiliary systems in a plant can be accurately modeled. • In response to numerous questions on the feasibility of a plant design with the new voltage and frequency ride through curves, the Standard Drafting Team responded that "The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs." Thus the SDT has recognized that the technology to comply does not exist today. • Southern Company noted that "We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers." • Duke Energy states in their comments, "An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed." • Indiana Municipal Power Agency questioned whether the technology to meet this requirement was currently available to a newly built generating facility. "To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the grid on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available?" • In a previous posting of the standard, GenOn Energy suggested "It does not appear that the SDT has carefully considered the possible impact of Attachment 2 on plant electrical auxiliary motors and contactors. The SDT should ask a power plant engineering company the impact on the electrical auxiliaries of an 800MW coal unit with a scrubber." If a solution is identified prior to implementation, preliminary estimates suggest the potential cost of complying with wider standards might increase machine costs as much as 25%, which is not insignificant. The result would be a considerable increase in capital and O&M2 costs for new (non-wind) generation due to increased equipment costs to meet more robust design specifications. The increase in costs, in combination with the compliance risk associated with not having a technical solution available at time of construction, will likely discourage new power plant construction outside of wind generation. This barrier to new construction could lead to mid-term reliability concerns, particularly in markets already stressed with tight reserve margins. Finally, the Standard Drafting Team has not demonstrated a grid-wide reliability gap justifying the need for voltage ride through for traditional (non-wind) generators. • The US Bureau of Reclamation noted "We believe there is no convincing reliability based rationale to expand the scope of the FERC Order via this standard to include synchronous machines, noting that Generators are already required (PRC-001-1) to coordinate settings with the host Transmission Operator." Both EPRI and IEEE have held discussions on this topic and have expressed concerns related to those issues noted previously. While these legitimate concerns about voltage ride through requirements for non-wind generators are being debated, they are also holding up other significant issues to be addressed by PRC-024 such as relay setting coordination and frequency ride through. Discussion, Frequency Ride-Through The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1 are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions that are unsafe. Please see in this respect the SERC Generation Subcommittee Nuclear Plant Review of PRC- 024 Curves presentation made at the SERC Engineering Committee Meeting of March 16, 2011 at Charlotte, NC. Steam turbine off-frequency limits are moreover generally subject to lifetime duration limits, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated. Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. 2 Additional costs associated with maintaining voltage sensitive equipment (power transformer, rotating equipment, breaker controls, etc.). Fan and pump performance will be affected at the frequency limits of Att. 1, and belowrated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. The basis of compliance for new units is simply, "will not trip," i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting-down the new power plant industry unless an owner were willing to take unbounded risk. A "will not trip" obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. It is noteworthy in this respect that environmental regulators have for decades been pushing gas turbine dry low-NOx combustors to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances, and there were in fact many gas turbine flameout trips during the blackout of '03. Greater consideration of BES reliability may be needed, but doing so by issuing dueling regulations would not constitute an appropriate approach. That is, we believe that passage of PRC-024 in its present form would cause the available design room between environmental and NERC regulations for gas turbines to become less than zero, so merely allowing time for development of new designs is not a solution. NERC, the EPA, OEMs and industry groups need to develop a mutually acceptable set of performance requirements. Other Concerns M5 of PRC-024 causes new-unit tripping due to frequency or voltage excursions within the specified limits to constitute a violation, but it is unlikely that "or" events would occur. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors would be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 in this standard. The grandfathering of existing units in R1 and R2 for, "documented and communicated equipment limitations," is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations, flame-out and the like during Disturbances will not be defined in OEM literature, nor is it possible to predict by calculations when such problems will occur, especially if a complex Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true Page 8 of 8 regarding predicting transient fluctuations of aux bus voltages, ref. risk of contactor drop-out and stalling major auxiliary equipment. The concern above applies also to having to make reference per R3 to, "study results, experience from an actual event, or manufacturers advisory." Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1 and Att. 2. The list of types of evidence in R3 is not exclusive; but it is difficult to imagine alternative forms of hard evidence that could be developed, other than for the comparatively few plants that possess high-fidelity dynamic simulators. The same concerns regarding availability of information apply for the, "estimate of the time duration the existing generation unit will remain connected," in R4. Relying on "sound engineering judgment" is permitted, and R4 states that "detailed unit performance studies are not required;" but the word "sound" implies that the estimate is to be based on accurate data, and such information could be developed only via a detailed study (which, as noted above, would be impossible to perform). The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to "protective relaying," which per footnote #1 in PRC-024 includes "protective functions within control systems…based on frequency or voltage inputs." It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions. Confusion is created by making grandfathering of protective relay settings, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." It is semantically unclear whether or not any grandfathering is actually being allowed. The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may again effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. Conclusion & Recommendation Based on the issues discussed above, the SRT recommends against adoption of Draft 4 (dated Oct. 4, 2012) of PRC-024-1. Furthermore, the SRT recommends that a deputation of NAGF members meet with the SDT for the purpose of developing a mutually-acceptable draft standard. This effort should include discussions with OEMs and industry groups regarding identifying the technical state of the art, and also with environmental regulators, if necessary, for achieving suitable emissions vs. BES reliability balance.

Individual
Mahmood Safi
Yes
Yes
Footnote 1, which is referenced in R1 and R2, has two separate purposes: one is to provide a definition of frequency or voltage protective relaying, and the other is to state that each Generator Owner is not required to have frequency or voltage protective relaying installed or activated on its unit. Accordingly, it should be split into two separate sentences. We recommend that Footnote 1 be replaced by the following paragraph: Frequency or voltage protective relaying includes but is not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency, speed, or voltage inputs. Each Generator Owner is not required to have frequency or voltage protective relaying installed or activated on its unit. Note the addition of the word "speed" in the definition of frequency or voltage protective relaying.
Group
seattle city light
paul haase
No
Seattle City Light votes NO because it is unclear the type of data the Reliability Coordinator, Planning Coordinator, Transmission Planner, and/or Transmission Operator is to provide the Generator Operator. Until Reliability Coordinators, Transmission Planners, Planning Coordinators, and/or Transmission Operators agree to and approve acceptable simulations and dynamic models, it is difficult for Seattle City Light to approve this standard. There are requirements included in R4 and R5 that have not been communicated with Generator Operators in the past, and without agreement about simulations and models, it is simply too unclear.
Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner should be added to the Applicability section because one or another of these are asked in R4 to provide information to the Generator Operator to begin the evaluations.
Individual
Daniel Duff
Agree
NAGF
Individual
John Yale
Agree
North Amnerican Generator Forum
Group
MEAG Power
E Scott Miller
Agree
Southern Comnpany Services, Inc. - Gen MEAG Power intended to vote NEGATIVE on this ballot. The Affirmative vote is an error. If the draft standard is not changed based upon the comments, MEAG Power will vote Negative on the Recirulation ballot.
Individual
Scott Berry
Agree
Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum (NAGF)for PRC-024.
Individual
Eric Salsbury

Consumers Energy's previous comments - “Related to undervoltage criteria, the 18 cycle at 45% of generator voltage would put a great deal of strain on the plant auxiliary systems and that may not be something these systems are able to withstand. The same would be true of a fault that produces 65% voltage at the generator terminals for 2 seconds. These comments relate specifically to Consumers Energy. However, it is likely that many others have similar equipment and would have the same issues. Please also note that the proposed standard does not align with ANSI C37.102, IEEE Guide for AC Generator Protection or with the NERC Technical Reference Document entitled Power Plant and Transmission System Protection Coordination.” Previous SDT reply - Thank you for your comments. Please note that the voltage levels specified in Attachment 2 are at the point of interconnection to the transmission system. They would not correlate directly with the auxiliary bus voltages, especially if the auxiliaries are unit-connected. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. Please inform the SDT of the specifics of your concerns. We believe our comments still apply. Specific to the fault that produces 65% voltage at the generator terminals for 2 seconds, plant auxliary equipment would not be able to withstand such a drop for the specified duration and would fall offline.
Individual
RoLynda Shumpert
Yes
Yes
Individual
Eric Bakie
Yes
Idaho Power System Planning agrees with the revised VRFs for R1, R2 and R5.
Yes
Idaho Power System Planning agrees with the revisions made to R4.
Requirement R1 and R2: Idaho Power System Planning comments that the GVSDT clarify if this standard applies to voltage or frequency elements only or if it applies to all generator protection elements as suggested in footnote 1. Requirement R5: Idaho Power System Planning comments that the GVSDT consider adding an exception to Requirement R5 that generation may trip if the Generator Owner has a documented over/under frequency limitation that cannot meet the stepped “no trip” curve shown in Attachment 1 provided that the Generator Owner and Transmission Operator have a documented mitigation plan approved by the Reliability Coordinator to trip equal load for instances of anticipated generation loss (similar to Item 13 of the WECC Off-Nominal Frequency Load Shedding Plan). Page 20: Idaho Power System Planning comments that the GVDST should clarify if Items 6a-6c are expected to be met simultaneously as it is not likely that a generator be capable of operating at full load (Pmax) and 0.95 pf lagging continuously. Idaho Power System Planning comments that the GVDST consider a 0.95 leading power factor condition in addition to the item included in Items 6a-6c. Requirement R6 is overly burdensome with questionable impact on reliability. Items 6a-6c on page 20 are not consistent with nor relevant to normal relay setting development practice. Initial operating points should be developed from good engineering judgement, not prescribed in this way.
Individual
Maggy Powell
Yes
No
In response to Exelon's (and other commenter's) concern that 60 calendar days was not a reasonable amount of time to perform a study in response to a written request from a RC, PC, TOP or TP, the GVSDT stated that it has "modified the structure of the requirement to clarify the intent and the limits of what entities could request a performance estimate;" but the GVSDT was not in agreement with changing the time period allowed to respond. Although the GVSDT states that "[d]etailed unit performance studies are not required to develop the estimate," Exelon continues to maintain that 60 calendar days is not a reasonable amount of time to perform a study of this magnitude based on the predicted scope. Specifically, nuclear generating units have extensive calculations related to how internal systems will respond to frequency and voltage excursions. Exelon believes it is inappropriate to short cycle or challenge the rigorous process required by the Nuclear Regulatory Commission (NRC) at a nuclear generating unit for any such study. In addition, depending on the complexity of the transient requested by the transmission entity, a nuclear generating unit may not have the in-house expertise to perform such a study and

may be required to hire an outside vendor.
Exelon is concerned that there are no set criteria for the transients nor any guidelines in the Standard on the number of requests that the RC, PC, TOP or TP could ask for. This is problematic in that the generating units could be subject to multiple requests for different combinations of transients without any cost benefit or justification. Exelon therefore suggests that the GVSDT evaluate adding language to the Standard that includes a provision for a set periodicity in which the transmission entities can request such data (e.g., an annual request or following a significant event on the transmission system). Exelon previously requested that the GVSDT split the Off Normal Frequency Capability Curve (Attachment 1) be split into separate tables for each Interconnect to make it easier to read. The response from the GVSDT states that they do not believe adding more graphs would add clarification since there are separate data tables. Although Exelon agrees that you could reference the data tables to ensure you are following the correct curve; unless the Off Normal Frequency Capability Curve is printed in color it is difficult to distinguish which line corresponds to which interconnection. Exelon still maintains that for clarity that each data table for each Interconnection should have a separate corresponding graph.
Individual
Daniela Hammons
No
(a) To improve clarity, CenterPoint Energy recommends deleting the second and third sentences of the first paragraph of R4. CenterPoint Energy does not agree that a Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner should provide a voltage or frequency profile at the point of interconnection that is determined by dynamic simulation. Different types of simulated events will produce different voltage and frequency excursions. Also, even the same type of event will produce different voltage and frequency excursion “profiles” as the system changes over time. (b) While deleting the second and third sentences of the first paragraph of R4 would provide clarity, it would nevertheless be problematic for reliability because it does not impose any minimum frequency or voltage ride-through requirements for existing generation stations. Failure of a generator to ride-through at least some minimum threshold of frequency and voltage excursions places the reliability burden solely on transmission entities and makes is difficult to compensate for the generator’s failure to perform.
(a) In R2 and R5, CenterPoint Energy recommends that “external to the generating plant” be deleted in the phrase “…caused by an event on the transmission system external to the generating plant…” We believe this could cause confusion, as some could consider the transmission interconnection substation as part of the generating plant. Also, such wording is not needed, as both requirements include the following clarifying language: “Generation may trip if clearing a system fault necessitates disconnecting a generating unit.” (b) CenterPoint Energy cannot support this version of PRC-024 because it does not impose any minimum frequency or voltage ride-through requirements for existing generation stations. Failure of a generator to ride-through at least some minimum threshold of frequency and voltage excursions places the reliability burden solely on transmission entities. This makes is difficult to compensate for the generator’s failure to perform and, therefore, is problematic for BES reliability.
Individual
Kirit Shah
Yes
Yes
(1)We commend the GVSDT for considering and addressing our previous comments, and making several changes that improve this proposed standard. (2)In R1 and R2, please add “Generation may trip by properly set volts per hertz protection if a system over excitation abnormality necessitates disconnecting a generating unit.” (3)Based on the GVSDT response to our previous comments we understand the purpose of R6 is to be studies. Given this study purpose, please change “and Transmission Planner” to “or Transmission Planner”, delete “monitors or” and replace “unless otherwise directed by the requesting Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner” with “while the requestor’s study is underway”. We believe that it is burdensome for the GO to have to indefinitely continue to send setting changes to the requesting entity. When the requesting entity begins another periodic study, they’ll request them again. Therefore, we request that R6 should then read: “Each Generator Owner shall provide its generator protection trip settings to the Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner (that models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings while the requestor’s study is underway.” (4)We believe that M5 expects the GO to retain evidence that proves the negative and is therefore burdensome. Generators trip for many reasons; most of them have to do with the mechanical system. We request that the SDT append “by the generator frequency or voltage protective relaying” after “each unit trip”, and add “or that no such unit trips occurred within the Data Retention period” at the end. M5 should then read: “Each Generator Owner shall have evidence, such as dated unit output

records, trip investigation reports or disturbance monitoring records, showing that each unit trip by the generator frequency or voltage protective relaying did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied, or that no such unit trips occurred within the Data Retention period.” (5)VSL’s in R3, R4, and R6 are set up with 10 day increments between the different severity levels, rather than a more typical 30 day increment. (6)As a general comment, NERC should make all the papers listed in the references section of the standard readily available on their website.
Group
JEA
Thomas McElhinney
JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Group
Luminant
Brenda Hampton
Yes
No
Because R4 is only requiring an estimate of a unit’s ability to ride through an excursion developed by a planner, the generator owner should only state if the unit is or is not capable of staying on-line. R4 should be written to follow the FERC order. It is recommended that R4 be written as such. R4) Each Generator Owner of a generating unit shall respond within 60 days of receipt of a written request by the requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner that monitors or models the associated generating unit) stating if generating unit(s) or plant is or is not expected to ride through a frequency or voltage excursion based on a dynamic simulation provided by the requestor.
The following is a copy of a white paper that was sent to generator owners and other industry organizations on requirements R4 and R5. At the end of the paper are Luminant’s recommendations for this standard. NERC Reliability Standards Project 2007-09 Generator Verification PRC-024 Generator Performance During Frequency and Voltage Excursions October 22, 2012 Introduction Project 2007-09 Generator Verification includes draft standard PRC-024, Generator Performance During Frequency and Voltage Excursions. Requirements R3 and R4 are for existing generating units. R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented cases where generator protective relaying cannot be set and directs those generators to communicate that limitation to the RC, PC, TOP and TP so its performance can be modeled correctly. R4 requires a Generator Owner to estimate the time duration for remaining on-line based on a Transmission Planner’s dynamic study. Requirement R5 directs all new generating facilities to be designed, built and maintained so that they are able to ride through the excursions defined in Attachment 1 and 2. Background In FERC Order 661 (June 2, 2005), Final Rule on Interconnection for Wind Energy, the Commission adopted a low voltage ride-through standard for wind generators, but provided that a wind plant is required to meet the standard only if the Transmission Provider shows, in the System Impact Study, that low voltage ride-through capability is needed to ensure safety or reliability. The standard, if applicable, requires the wind plant to stay online for specified time periods and at associated voltage levels where there is a disturbance on the transmission system. Several entities requested rehearing of various aspects of the low voltage ride-through requirement and standard included in the Final Rule. In FERC Order 661-A (December 12, 2005) page 2, the Commission noted “that the standard interconnection procedures and agreement were based on the needs of traditional generation facilities and that a different approach might be more appropriate for generators relying on other technologies, such as wind plants. Accordingly, the Commission granted certain clarifications, and also added a blank Appendix G to the standard Large Generation Interconnection Agreement (LGIA) for future adoption of requirements specific to other technologies.” The Commission went on to adopt in Appendix G to the LGIP limited special interconnection procedures applicable to wind plants only. The basis for the change to the standard regarding voltage ride through starts with FERC Order 693, Paragraph 1787 (March 16, 2007), which states “… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. “ Discussion / Reliability Impact Although FERC Order 661-A does make a provision for future adoption of voltage ride-through requirements for all generators, the Order is careful to differentiate between wind generation technologies and other, traditional generation facilities. No instruction is given for other technologies in the Order. Nowhere in any of the FERC Orders (661, 661A, 693) is there a single requirement for non-wind generators to meet ride-through requirements. Docket No. RM05-4-000

(Order No. 661) discusses this subject directly. The Notice of Proposed Rulemaking (NOPR) Interconnection for Wind Energy and Other Alternative Technologies dated January 24, 2005, sought comments on certain specific issues, including whether there are other non-synchronous technologies, or other technologies in addition to wind, that should also be covered by the proposed Appendix G. In FERC Order No. 661, the Final Rule on Interconnection for Wind Energy, the Commission noted "These technical requirements for the interconnection of wind plants recognize the unique design and operating characteristics of wind plants, their increasing size and increasing level of penetration on some transmission systems, and the effects they have on the transmission system." Further, they wrote, "The Final Rule Appendix G we adopt here applies only to the interconnection of wind plants. The Commission does not believe at this time that the standard procedures and technical requirements in this Final Rule are appropriate for other alternative generating technologies that may supply over 20 MW at one Point of Interconnection. The standard procedures and technical requirements adopted here recognize the unique characteristics of wind plants, including the fact that they use induction generators, consist of several or numerous small generators connected to a collector system, and do not respond to grid disturbances in the same manner as large conventional generators." The Final Rule also noted that while low voltage ride-through capability is needed for wind plants, it is less of a concern for large synchronous generating facilities because most of these facilities are equipped with automatic voltage control devices to increase output during low voltage events. The Commission concluded that the Final Rule Appendix G exceptions to the LGIP and LGIA apply only to large wind plants. Appendix G was designed around the special needs and design characteristics of wind generators. The Appendix G provisions adopted "focuses on the special characteristics of large wind plants, particularly the fact that they utilize many induction generators connected to the transmission system at a single point through a medium-voltage collector system. The Commission has not found at this time that any other technologies, including the solar generators without fueled backup …, have similar characteristics." The Project 2007-09 Generator Verification Standard Drafting Team has presented the current draft of the standard as a technology-neutral version, ignoring the fact that power plant performance in asynchronous vs. synchronous units for transmission excursions are significantly different and are technology dissimilar for reasons of voltage regulation ability and plant auxiliary design. • The NERC System Protection and Control Subcommittee wrote, in previous comments, "FERC 661-A is a wind generator facility ride-through performance criterion, not a synchronous generator relay setting requirement. They cannot be considered as being the same. This requirement in PRC-024 should only apply to non-synchronous machines." • Constellation Power wrote, "The idea of a ride-through curve originated with wind farms, and is not conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines." • PPL Energy commented, "PPL is concerned with the following concepts in the standard: 1) The standard applies equally to asynchronous and synchronous machines, salient pole and round rotor machines, photovoltaic, and other resources and as such the standard does not appear to recognize that these technologies respond differently to voltage and frequency excursions." • AEP posited "The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied." • Pacificorp offered "Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms." Furthermore, OEM's have not yet developed a solution to voltage ride through for non-wind generators. Assured compliance with PRC-024 may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. Regulation should not come before a solution is available. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of medium and low voltage auxiliary systems in a plant can be accurately modeled. • In response to numerous questions on the feasibility of a plant design with the new voltage and frequency ride through curves, the Standard Drafting Team responded that "The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs." Thus the SDT has recognized that the technology to comply does not exist today. • Southern Company noted that "We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers." • Duke Energy states in their comments, "An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed." • Indiana Municipal Power Agency questioned whether the technology to meet this requirement was currently available to a newly built generating facility. "To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the grid on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available?" • In a previous posting of the standard, GenOn Energy suggested "It does not appear that the SDT has carefully considered the possible impact of Attachment 2 on plant electrical auxiliary motors and contactors. The SDT should ask a power plant engineering company the

impact on the electrical auxiliaries of an 800MW coal unit with a scrubber.” If a solution is identified prior to implementation, preliminary estimates suggest the potential cost of complying with wider standards might increase machine costs as much as 25%, which is not insignificant. The result would be a considerable increase in capital and O&M costs for new (non-wind) generation due to increased equipment costs to meet more robust design specifications. The increase in costs, in combination with the compliance risk associated with not having a technical solution available at time of construction, will likely discourage new power plant construction outside of wind generation. This barrier to new construction could lead to mid-term reliability concerns, particularly in markets already stressed with tight reserve margins. Finally, the Standard Drafting Team has not demonstrated a grid-wide reliability gap justifying the need for voltage ride through for traditional (non-wind) generators. • The US Bureau of Reclamation noted “We believe there is no convincing reliability based rationale to expand the scope of the FERC Order via this standard to include synchronous machines, noting that Generators are already required (PRC-001-1) to coordinate settings with the host Transmission Operator.” Both EPRI and IEEE have held discussions on this topic and have expressed concerns related to those issues noted previously. While these legitimate concerns about voltage ride through requirements for non-wind generators are being debated, they are also holding up other significant issues to be addressed by PRC-024 such as relay setting coordination and frequency ride through. Summary and Conclusion The Standard Drafting Team should remove Requirements R4 and R5 from the current version of PRC-024 to facilitate passage of the more critical elements of the standard such as voltage and frequency relay setting requirements. The current technology neutral draft standard PRC-024 is inconsistent with the intent of FERC Order 661 -A in that it applies “equal” requirements to all generators, rather than requirements solely for wind generators which is the focus of the FERC Order. The Standard must recognize that wind generators and traditional generation facilities are technologically dissimilar and, therefore, cannot be treated the same in this instance. With no technology currently commercially available to provide guaranteed voltage ride through capabilities for traditional generation, the standard should not require this (unavailable) technology be in place in order to meet the requirements of the standard. When the technology becomes available, a new SAR may be drafted to address the voltage performance aspects of non-wind generators if an identified reliability gap exists. The new Cost Effective Analysis Process can be used at that time to evaluate the costs and benefits associated with the new requirement, as well as facilitate consideration of alternative methods to achieve the reliability objective which may result in less implementation costs and resource expenditures.
Individual
Don Jones
Yes
Yes
1) R5: New generation units may not be able to meet this requirement if auxiliary systems are included. While the standard allows for a temporary or retroactive exemption, it is a difficult task to design and build a new plant and take into account the myriad of pumps, fans, dampers, control systems, instrumentation, etc. that could possible trip the unit during a low frequency or low voltage event. The SDT may want to consider removing the language “and plants (including auxiliary systems)” from the first sentence of this requirement. If the SDT maintains this requirement, consideration should be given to utilizing a lower VSL other than Severe. Additionally, considering the proposed efinition of BES, is the auxiliary system phrase applicable? 2) As written, the standard will apply across all types of BES-defined generation units (Individual generating unit greater than 20 MVA directly connected to the bulk power system, generating plant/ facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA, etc.) regardless of fuel type. Based on this applicability, fossil-fueled conventional units and variable resources (wind, solar, hydro, etc.) must meet the same voltage/frequency criteria. Is this the intent of the SDT? Voltage ride-through capabilities can vary significantly between fossil-fueled plants and wind plants due to their technical dissimilarities. Attempting to apply a single criteria to both will lead to technical difficulties between synchronously-connected and asynchronously-connected machines, as each responds differently voltage disturbances. Attempting a one-size-fits-all approach is inappropriate for this type of standard. The standard should recognize that wind generators and traditional generation facilities are technologically dissimilar and, therefore, cannot be treated the same in this instance. 3) If a Generator Owner has a limitation that is communicated but failed to set its frequency protective relaying to not operate, is that a violation? 4) Has there been any consideration of providing separate capability curve figures for each Interconnection?
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
No

(1) We question the value of this requirement and suggest it should be struck. While knowing how long a generator will remain connected following a voltage or frequency excursion might be useful to a planning engineer conducting dynamic simulations, we do not see how it helps the RC, BA or TOP. The RC, BA or TOP's System Operator will not likely take any action as a result of such information. Rather, they will wait to see if the unit trips before taking additional action because there is no guarantee the unit will trip. Then, they will already be taking actions to minimize the stress regardless of whether they suspect that a unit may trip due to a voltage or frequency excursion. System Operators always have to be prepared to respond to events but simply cannot be expected to respond to every possible event because most simply don't happen and it would be an unreasonable expectation of System Operator. Even if the System Operator knew that a unit might trip in a short time frame due to a voltage or frequency excursion, they simply do not know when such an excursion might or even will occur and likely would not take preemptive action. Because System Operators are responsible for monitoring many aspects of the BES, it would be a waste of time to have them speculating whether or not a unit is going to trip. The system operator only needs to know how to react and mitigate the event if a unit does in fact trip. Furthermore, the RC, BA, and TOP already operate the system to withstand the loss of a unit so any unit that would trip due to such an excursion would not cause a problem. Upon the actual unit trip, then the RC, BA and TOP can reposition the system if necessary to prepare for the next contingency. When information is supplied to a System Operator that does not require them to do something it becomes "noise" which provides no value. (2) IRO-010-1a and TOP-003-2 already allow the RC and TOP to request necessary data from the Generator Owner through their data specification and have the authority to compel the Generator Owner to provide the data. Thus, if this data is needed the RC and TOP will include it in their data specifications. As a result, supplying the portion of R4 that requires data to be supplied to the RC and TOP is redundant and unnecessary. (3) What level of voltage or frequency excursion is intended to be covered by this requirement? It does not appear to be specified.
(1) We appreciate that the second bullet allows that TP to provide a less stringent voltage envelope for R5. However, it is not clear if the TP can provide a more stringent envelope. We believe a more stringent voltage envelope should not be allowed. Please clarify. (2) We continue to believe that requirement R5 needs to be modified to recognize that equipment will not always be new and may develop limitations as it ages. These limitations may prevent the generator from meeting the voltage and frequency envelopes defined in Attachment 1 and 2. (3) Requirement R6 should be struck. First, the TOP and RC already have the capability to request such data in its data specification from the GO through IRO-010-1a and TOP-003-2 which also compels the GO to comply with the data specification. Thus, if the TO and GO need the data they will write it into their data specifications. Second, this requirement is the type of requirement that the Project 2013-02 Paragraph 81 drafting team has proposed eliminating in response to the FERC approval order of the FFT process. Specifically, the requirement meets the Administrative, Purely Reporting and Redundant criteria for the project. It only has to meet one criterion to be proposed for retirement. It is imperative that drafting teams refrain from developing requirements that a future team will retire. (4) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls, entity impact evaluation, elimination of zero-defect expectations). The VSL for Requirement R5 makes it clear that every time a "new unit" (i.e. does not meet footnote 2) trips, an evaluation needs to be conducted to determine if the unit tripped for a voltage or frequency excursion that is inside the no trip zone. To refocus NERC efforts on compliance, the recent compliance enforcement initiatives would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. These approaches are being written into the standards (CIP, COM-003, etc.). We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this requirement. (5) Because the voltage envelope is based on assumptions listed on page 20, the VSLs for R5 need to clarify that if a unit does trip in the no trip zone and the system does not reflect these assumptions that this does not represent a violation. For instance, if a synchronous condenser or capacitor (bullet 7 on page 20) is not available that was assumed to be available when evaluating protection relay settings, why would the GO be held accountable for its unit tripping during a voltage excursion? It followed the assumptions set out in the standard. (6) Why is the defined term Protection System not used throughout the standard rather than "protective relaying"? We recommend adopting the NERC Glossary Term for consistency. (7) We continue to believe that performance requirements for new units should be part of the interconnection process. As a result, R5 should either be struck or it should be moved to FAC-001 which governs standards for facility connection requirements. (8) Requirement R3 and R6 are the types of requirements the Project 2013-02 Paragraph 81 drafting team is proposing to eliminate. They have established a set of criteria to identify requirements with little to minimal reliability impact. Both of these requirements meet one or more of the following criteria: Administrative, Purely Documentation, Purely Reporting, or Little, if any, value as a reliability requirement. Please review all proposed requirements against this criteria and remove requirements as appropriate. While we believe R3 should be removed, we do understand there is a need to document equipment limitations for R1 and R2. We believe the existing associated bullets in R1 and R2 will satisfactorily address the need to document limitations and that the reference to R3 could simply be struck. (9) Please remove the RC and TOP from Part 3.1 of R3. Inclusion of the RC and TOP is redundant with IRO-010-1a and TOP-003-2 which require the RC and TOP to develop data specifications. If they need this data, it should be included in their data specification. (10) Please remove "as specified by Requirement R6" in the first half of the R6 VSLs. We found it confusing when it was not included in the second half. (11) Please copy footnote 1 from R1 on to the page with R2. It was not immediately clear that he footnote in R2 was actually on the previous page.
Individual
Marie Knox

Agree
The ISO/RTO Council’s (IRC) Standards Review Committee (SRC)
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
Yes
No
The Protective Relay coordination portions of this standard are not being contested. It is not clear how the evaluations should be performed to determine the ability to ride through grid transients. A standard should NOT be written to require this until research has been done to document an appropriate approach to doing these evaluations. It is suggested that plant performance requirements be removed from this Protection System (PRC) standard. If this is required to support grid reliability, then a new SAR should be written to develop those plant performance requirements.
Looking at the Table for the Eastern Interconnection in Attachment 1 of the Standard, this table does not correlate to our company procedures for EOP-003, in which generators are expected to isolate from the system anytime the frequency goes to 58.2 Hz or lower. The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1 are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions that are unsafe. Please see in this respect the SERC Generation Subcommittee Nuclear Plant Review of PRC-024 Curves presentation made at the SERC Engineering Committee Meeting of March 16, 2011 at Charlotte, NC. Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. See also in this respect the AREVA NP White Paper on PRC-24. Auxiliary equipment contactors are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses. Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to “protective relaying,” which per footnote #1 in PRC-024 includes “protective functions within control systems…based on frequency or voltage inputs.” It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions. The basis of compliance for new units is simply, “will not trip,” i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting-down the new powerplant industry unless an owner were willing to take unbounded risk. A “will not trip” obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. “It is noteworthy in this respect that environmental regulators have for decades been tightening gas turbine dry low-NOx combustor emissions limits, taking these devices to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances, and there were in fact many gas turbine flame-out trips during the blackout of ’03. That is, the EPA and NERC may be trying to achieve divergent and even incompatible goals, so merely allowing time for development of new designs is not a solution. NERC, NAGF, the EPA, OEMs and industry groups should develop a mutually acceptable set of performance requirements.” M5 causes new-unit tripping due to frequency or voltage excursions within PRC-024 limits to constitute a violation, but it seems unlikely to expect an “or” event. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 in this standard. The grandfathering of existing units in R1 and R2 for, “documented and communicated equipment limitations,” is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations and the like during Disturbances will not be defined in OEM literature, nor is it generally possible to predict by calculations when such problems will occur, especially if a Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true regarding predicting transient fluctuations of aux bus voltages, ref. risk of contactor drop-out and stalling major auxiliary equipment. The concern above applies also to having to make reference per R3 to, “study results, experience from an actual event, or manufacturer’s advisory.” Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1 and Att. 2. The list of types of evidence in R3 is not exclusive, but it is difficult to imagine alternative forms of hard evidence that could be developed other than for the comparatively few plants that possess high-fidelity simulators. Confusion is created by making grandfathering, “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such protective relays meant to correspond to the “protective

relaying" discussed above? It is unclear whether or not any grandfathering is actually being allowed. The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. Steam turbine off-frequency limits are generally set by OEMs lifetime limits as regards duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated.
Individual
Mary Downey
Agree
SMUD/BANC
Individual
Joe Tarantino
No
We agree that a GO can meet the requirements in R1 & R2 and use R3 to note any known limitations. We do not feel the GO can provide any meaningful estimate of overall plant performance beyond meeting the first three requirements. The complexity of what is being asked is simply too great.
We much prefer a performance based, RBS approach using the internal controls process than the approach taken by the SDT. We would prefer to evaluate post event trips for compliance with the settings rather than keep extensive, zero-defect compliance documentation for all unit settings. (Intentional Space).... Specific Comments: It appears that R1 & R2 are meant to be "document the settings" requirements since they refer to the Long-term Planning Time Horizon and M1 & M2 ask for settings documentation. The requirements themselves suggest that compliance is evaluated based on actual events, though. For instance, the first bullet in R1 mentions "..impending or actual loss of synchronism.." which would not be evaluated in the Long-term Planning Time Horizon. R2 states "…such that the voltage protective relaying does not trip…" which again implies evaluating the results of an actual event. R1 & R2 are not clearly pre-event documentation only or post event analysis only – they currently try to have it both ways. Please correct this. (Intentional Space).... We agree with the compliance approach used in R5 and encourage the SDT to use this same approach for requirements R1 & R2. SMUD recommends the following changes the the 5th bullet of R5: (Intentional Space).... "Generation may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation. If a legitimate equipment limitation is identified following a plant trip caused by a frequency or voltage excursion, the Reliability Coordinator shall grant a retroactive exemption for the identified limitation." (Intentional Space).... The stuck language lends itself to arbritaray determinations and, where no fix is possible, automatically forces a non-compliance situation for an unknown condition. (Intentional Space).... We disagree with R6. First, the GO must provide the generator protection trip settings – this phrasing is not limited to voltage or frequency trip points, but ALL trip settings. This is unreasonable. Second, the GO should not be subjected to an indefinite requirement to constantly update an entity that sends a single written request. By the requirements in this standard, the various Coordinators and Planners know that the plant's trip settings must follow the curves. Why isn't this enough? If the Coordinators or Planners want specific setting data, they should be required to ask for it each time. Otherwise, they should model the plant as meeting the curves contained in this standard.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery, NERC Reliability Compliance Coordinator
Yes
No
As currently drafted, Requirement R4 appears to dictate an analysis for all inflection-points in unit performance, for a continuum of frequency and voltage excursions, and taking into account all of the underlying auxiliary equipment's control systems and settings. We see this current draft's Requirement R4 wording as a creating a much greater expectation, than estimating the duration-times for the curves at the specific inflection-points given in Attachments 1 & 2 of this Standard.
Requirement R3 qualifies "each known equipment limitation". Measure M3 omits the "known" qualifier, stating the expectation of measurement is to have "any equipment limitations" documented. Is the expection for "any" to mean "some", or "all known"?
Group
Duke Energy
Greg Rowland

Yes
No
1) It is unclear if this requirement is to be only upon request, and if requests will be related to the same ride through criteria or a different set specified by the TP. Need to clarify how this aspect will be executed. 2) Refer to discussion in our response to Question 3 below about industry concerns with the technical viability of plant performance standards.
1) Feedback from the IEEE Electric Machines Committee and Siemens (a generator equipment OEM) serve as the bases for these statements and are included below. PRC-024 was orignially intended to address a relay setting/coordination issue. This appears to be addressed by the current draft of the standard. However, the issues related to plant survivability or performance are more complex. It is not appropriate to attempt to address these issues in a PRC standard. The addition of plant performance aspects appear to be driven by FERC as evidenced by the minutes of the May 2009 meeting - see http://www.nerc.com/docs/standards/dt/GVSDTnotes052809.pdf. 2) According to attendees at the IEEE EMC meeting, much of the technical justification for the need of a plant performance criteria was based on issues with early design wind generation, however the technical considerations at these types of generation stations are different that steam turbine generation plants, which require heavy induction loads to support operation. These loads are sensitive to upsets in voltage and frequency. The technical implications of the plant performance are not clear and thus this issues should not be standardized at this point in time. It is recommended that the plant performance aspects be removed from the PRC standard and a new SAR be written to address plant performance requirements. This approach would support pulling in the various design expertise (IEEE, Equipment OEMs, Power Plant Design entities, etc) needed to develop a technically correct ride through criteria. 3) There also is a need to develop industry accepted methods to determine the capability of a plant to ride through grid transients prior to this becoming a mandatory standard. 4) It appears the +/- 5 % of the rated generator voltage constraint has been removed from the voltage ride thru criteria. Depending on the tap of the GSU, this might be more limiting than the HVRT curve. SDT should consider keeping the constraint. 5) Related to #5 in the curve clarifications - What is the intend of changing from RMS to crest voltages for the HVRT? What is a crest phase-to-phase voltage? 6) Related to #6 in the curve clarifications - Voltage relays may not ride through HV or LV disturbances as intended if the curves are not compensated for the rated capabilities of the machine. It would be better to compensate the LVRT curve for operation at the B point on the D-Curve and the HVRT curve for operation at the C point on the D-curve. 7) V/Hz relay should be evaluated in the frequency domain at maximum rated voltage, typically 105%. 8) Has any consideration been given to addressing the frequency and voltage excursions in the transmission system in order to arrest the situation locally? 9) Information from IEEE Electric Machinery Committee discussion topic “Grid Code Impact on Electric Machine Design” (San Diego 2012 – Papers from the session with supporting information are available): A) PRC-024 VR capability may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. It is believed the cost of complying with wider standards might increase main generator machine costs as much as 25%, which is not insignificant. This should only be required if there is a defined local system need for higher standards and that these costs should be considered against the cost of other possible resolutions. B) A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of all 4160V and 460V systems in new plant can be dynamically modeled to a degree allowing one to obtain non-drop-out guarantees from equipment suppliers and EPC firms for extreme transients such as 2.0 seconds at 65% voltage, or that the same can be done for existing plants to allow identification of limiting components and accurate estimates of performance. C) The voltage ride through was originally intended to address early deficiencies in wind generation design only and it doesn’t make sense to apply such a broad curve to steam plants. The concerns that led to the VRT curve for wind have been addressed by new vintage wind plant designs and thus, the EMC does not believe there is a driving need for a standard VRT criteria. 10) The VRT issue is holding up addressing other significant issues addressed by PRC-024 (relay setting coordination and frequency ride through). The VRT should be pulled out of PRC-024 and a new SAR drafted to address the voltage performance aspects if this is really needed for reliability. 11) Information from Siemens (Generator OEM) perspective: A) Regarding PRC-024, the LVRT curves (on Attachment 1) are subject to misinterpretation, since they seem to imply a very slow, stepped voltage recovery rather than a set of roughly equivalent faults. The curve needs some elaboration and supplemental explanation. B) The proposed PRC-024 draft allows certain exemptions (e.g., loss of field and loss of synchronism) that are not permitted in the stability assessment of wind plants. This appears to be in conflict with the FERC 693 mandate for technology-neutral ride-through requirements, since wind turbines have no analogous exceptions. Indeed, the reason for the LVRT standard applied to wind turbines was because of the characteristic of induction generator wind turbines to lose synchronism at low voltages. C) The Abnormal Frequency ride through curves of PRC-024 (on Attachment 2) have not been coordinated with the equipment standards and exceed the overfrequency limits in the equipment standards in most cases. D) Further on PRC-024, there is only one reference explicitly cited, yet there are several implicitly cited (e.g., frequency limits) and there are well-known conflicts with equipment standards. The sources of the frequency limits and equipment standard limits should be cited in publicly available documents. Where, for

example, are the Eastern Grid and ERCOT overfrequency requirements? They are not generally known. They should be explicitly cited. E) The LVRT curves stipulate that the stability assessment be performed at rated lagging power factor. This is not a conservative assumption. It should be justified, not simply asserted as standard practice.
Group
ISO RTO Council Standards Review Committee
Al DiCaprio Chair
No
The proposed language lacks clarity in what data is needed in order for a TOP to comply with the requirement to provide trip settings to the RRO/RC/Transmssion Planners. We recommend that regions develop further specific "no-trip" regions specific to their area of the Interconnection.
Individual
Tony Kroskey
Agree
ACES Power Marketing
Individual
Russell Noble
No
Requirement R4 is clear, however it can take 60 calendar days simply to find and retain a consulting firm who is qualified to provide the estimated data to the requesting entity. This will require the GO to perform defensive compliance, that is, to attempt to aquire data before a request is submitted in order to meet the tight two-month response time. There is no provision to allow the GO to negociate a time frame with the requesting entity.
Cowlitz supports the comments from the NAGF SRT: 1. The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1 are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions that are unsafe. 2. Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. 3. Auxiliary equipment contactors are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses. 4. Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. 5. The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to "protective relaying," which per footnote #1 in PRC-024 includes "protective functions within control systems…based on frequency or voltage inputs." It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions. 6. The basis of compliance for new units is simply, "will not trip," i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shuttingdown the new power plant industry unless an owner is willing to take unbounded risk. 7. A "will not trip" obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. It is noteworthy in this respect that environmental regulators have for decades been pushing gas turbine dry low-NOx combustors to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances. Greater consideration of BES reliability may be needed, but doing so by issuing dueling regulations would not constitute an appropriate approach. 8. M5 causes new-unit tripping due to frequency or voltage excursions within PRC-024 limits to constitute a violation, but it seems unlikely to expect an "or" event. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 in this standard. 9. The grandfathering of existing units in R1 and R2 for, "documented and communicated equipment limitations," is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations and the like during Disturbances will not be defined in OEM literature, nor is it generally possible to predict by calculations when such problems will occur, especially if a Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true regarding predicting transient fluctuations of aux bus voltages, ref. risk of

contactor drop-out and stalling major auxiliary equipment. 10. The concern above applies also to having to make reference per R3 to, "study results, experience from an actual event, or manufacturers advisory." Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1 and Att. 2. The list of types of evidence in R3 is not exclusive, but it is difficult to imagine alternative forms of hard evidence that could be developed other than for the comparatively few plants that possess high-fidelity simulators. 11. The same concerns regarding availability of information apply for the, "estimate of the time duration the existing generation unit will remain connected," in R4. Relying on "sound engineering judgment" is permitted, and R4 states that "detailed unit performance studies are not required;" but the word "sound" implies that the estimate is to be based on accurate data, and how such information could be developed without a detailed study is unclear. 12. Confusion is created by making grandfathering, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such protective relays meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any grandfathering is actually being allowed. 13. The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. 14. Steam turbine off-frequency limits are generally set by OEMs lifetime limits as regards duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated. 15. An additional "may trip" exclusion is needed for R1 and R2 related to V/Hz set properly to limit over excitation of generators or transformers. 16. Objection to R5 – the additional costs involved for re-designing generating stations so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability of a voltage and/or frequency excursion occurring. Furthermore, we believe it is fundamentally inappropriate to support approval of such a requirement until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved. We recommend this requirement be removed so the standard can move forward to address the shorter term goals that are achievable. 17. Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Also, this requirement may repeat requirements that are being developed in revisions to PRC-001. 18. It is inconceivable that most plants can ride through a + or - 10% voltage excursion for 10 minutes per PRC-024, Attachment 2. Almost all would have to take exception.
Individual
Don Schmit
Agree
MRO NSRF [MidwestReliability Organization - NERC Standards Review Forum]
Individual
Chifong Thomas
Yes
Yes
BrightSource is voting affirmative with the understanding that individual Regions can have requirements that are more stringent than NERC Standards. Therefore, even though R3 only requires GOs to "document each known equipment limitation (excluding limitations that are caused by generator frequency and voltage protective relays) that prevents a generating unit, from meeting the criteria in Requirements R1 or R2 ….", it does not relieve the GOs of their obligations under the WECC Coordinated Off-Nominal Load Shedding Plan for generators that connects to the Western Interconnection.

Consideration of Comments

Project 2007-09 Generator Verification
MOD-026-1

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to MOD-026-1. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 45 sets of comments, including comments from approximately 150 different people from approximately 97 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration

The majority of commenters agreed with the revisions to Attachment 1 that were made in response to comments in the previous posting. No modifications were made to the draft standard as a result of industry comments for Question 1.

The majority of industry agreed with the revised language to make it clear that technically justified units were limited to units that meet the NERC Registry criteria thresholds and that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. No modifications were made to the draft standard as a result of industry comments for Question 2.

The following clarifications were made to the standard in response to industry comments:

- Included the term "impedance compensation" to Footnote 1 in the description of what constitutes an excitation control system for synchronous machines.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

- The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."
- The wording, "… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities …" in Section 5.1 was moved to right after, "… approved by applicable regulatory authorities …" And that same wording was moved to right after, "… following applicable regulatory approval …" in Sections 5.2 to 5.4. Also, the same phrase was appended to each of the four bullets in the Effective Dates Section, "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after, "… following applicable regulatory approval ..."
- In the Effective Date section 5.3, the word "thirty" after the word "quarter" was inserted in the standard by mistake. As such, the SDT removed the word "thirty."
- Revised the first sentence in R1 to read: "Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request:" Stakeholders believed the previous language was not as clear as it could be, so the GVSDT made this revision.
- The SDT has refined the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s), or both." This ties the requirement to the applicability of the standard per stakeholder request.
- Refined sub part 2.1.2 to read: "Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed)."
- Clarified that the response by the Transmission Planner to the Generator Owner concerning the results of testing the model useability is required to be a written response (R6). Also, for ease of reading, moved the last sentence in the requirement to after the Requirement Parts 1-3.

Index to Questions, Comments, and Responses

1. The GVSDT has revised Attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below. 12

2. The GVSDT has revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that “technical justification” is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. Do you agree with these revisions? If not, please explain in the comment area below. 28

3. Do you have any other comment, not expressed in questions above, for the GVSDT? 40

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Domion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

				1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	John Allen	City Utilities of Springfiel	SPP	1, 4
3.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
4.	Sean Simpson	Board of public utilities of kansas city	SPP	1, 3, 5
5.	Mark Wurm	BPUK	SPP	NA
6.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
7.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
8.	Brian Taggert	Westar Energy	SPP	1, 3, 5, 6
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	John Mayhan	Omaha Public Power District	MRO	1, 3, 5
11.	Ron McIvor	Omaha Public Power District	MRO	5, 1, 3
12.	Mahmood Safi	OPPD	MRO	1, 3, 5
13.	Anna Wang	Burns McDonald	SPP	NA

				1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

5.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	Dewayne Scott		SERC	1
5.	Tom Vandervort		SERC	5
6.	Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	Goerge Pitts		SERC	1
9.	Robert Bottoms		SERC	
10.	David Marler		SERC	1

6.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1
2.	Chuck Matthews	Transmission Planning	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
3.	Erika Doot	Generation Support	WECC	3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Steve Kern	FE Energy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Frank Gavvney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	E Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Jackson	MEAG Power	SERC	3
2.	Steve Grego	MEAG Power	SERC	5
3.	Danny Dees	MEAG Power	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	John Shaver	Southwest Transmission Cooperative	WECC	1
3.	Tom Alban	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	James Manning	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Charles Long	SERC Planning Standards Subcommittee	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NCEMC	SERC	1
3.	Jim Kelley	PowerSouth Energy Coop	SERC	1
4.	Philip Kleckley	SC Electric & Gas Co	SERC	1
5.	Bob Jones	Southern Company Service	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Pat Huntley	SERC Reliability Corp	SERC 10										
7.	David Greene	SERC Reliability Corp	SERC 10										
8.	Amir Najafzadeh	SERC Reliability Corp	SERC 10										
15.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
16.	Individual	David Thorne	Pepco Holdings Inc and Affiliates	X		X							
17.	Individual	ryan millard	pacificorp	X		X		X	X				
18.	Individual	Brian Bejcek	Wolverine Power Supply Cooperative, Inc.	X									
19.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
20.	Individual	Jim Watson	Dynegy					X					
21.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
22.	Individual	Lynn Schmidt	NIPSCO	X		X		X	X				
23.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
24.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
25.	Individual	Winnie Holden	PSEG	X		X		X	X				
26.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
27.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)					X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
29.	Individual	Ken Gardner	Alberta Electric System Operator (AESO)		X								
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Wryan Feil	Northeast Utilities	X									
33.	Individual	Brian Evans-Mongeon	Utility Services								X		
34.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
35.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X	X	X	X				
36.	Individual	Scott Berry	Indiana Municipal Power Agency										
37.	Individual	Eric Bakie	Idaho Power Company	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
38.	Individual	John Yale	Chelan PUD					X					
39.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Don Jones	Texas Reliability Entity										X
42.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
43.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
44.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
45.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
MEAG Power	Southern CompanyServices, Inc. - Gen
Liberty Electric Power	NAGF
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

1. The GVSDT has revised Attachment 1 based on stakeholder comments. Do you agree with this revision? If not, please explain in the comment area below.

Summary Consideration: The majority of commenters agreed with the revisions to Attachment 1. No modifications were made to the draft standard as a result of industry comments for Question 1.

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	No	(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 2 provides guidance for early compliance and we agree that early compliance should be allowable. It establishes that 10 year period begins from the transmittal date. If a GO has data that satisfies the early compliance condition for a verified model and that data is a five years old, the Note would appear to allow the GO to transmit the data to the TP and receive credit for next 10 years effectively creating an initial 15-year re-verification cycle. Is this intended? If not, please provide more guidance for how soon the GO would have to re-verify its model. **Response: The intent of Attachment 1 Note 1 is to establish the recurring 10-year unit verification period start date assuming no consideration for early compliance. Consideration for early compliance is addressed in Note 2. This allows early compliance for a 10-year period. The 10-year period begins when model verification is specified to be "complete" per the regional policies, guidelines, or criteria that were in force. If early compliance is sought based on existing verification compliant with the requirements of this standard, as the SDT strove to write the standard such that the "how's" are specified and not the "what's", the modeling expert is expected to responsibly manage the time between the data**

Organization	Yes or No	Question 1 Comment
		used to verify the model and the subsequent verification and the transmittal of the verified model, documentation, and data to the Transmission Planner. (2) Row 3 in Attachment 1 states that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new excitation or plant volt/var control system. However, Requirement R4 also applies to changes to the controls systems. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. **Response: The SDT feels like the distinction of a complete replacement of an excitation system merits its own row in Attachment 1 as there is no doubt that this would result in the need to verify the model and is applicable to Requirement 2 and not Requirement 4. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** (3) Per Requirement R4 and Row 5 in Attachment 1 the GO has 180 days to submit a plan to Transmission Planner to verify the model and then another 365 days to perform the model verification date. That would appear to give the GO approximately a year and half to complete the verification for changes (including replacement) to the control system. Requirement R2 and Row 3 appear to require completion of the verification in 365 days or a year. Please modify the table or requirement to clarify appropriate application. **Response: The time lines for Requirements R2 and R4 are different as the Requirements are different. Requirement R4 specifies the need for model verification due to changes to the excitation control system and plant volt/var control function that alter the equipment response characteristic, and allows 180 days to determine if the model needs to be verified or if the submission of updated data is sufficient. Attachment 1**

Organization	Yes or No	Question 1 Comment
		addresses the required periodicity and acceptable time delays to remain compliant (365 days for activities described in R4 assuming for R4 that the Generator Owner decided that they will verify the model). Conversely, R2 specifies the periodic required model verification and thus no time needs to be allotted to determine if the model needs to be verified – as it must be verified at least once every 10 years. Attachment 1 goes on to specify the required time or anniversary date for which verification per R2 is required.
Response: The GVSDT thanks you for your comments. Please see responses above.		
Tennessee Valley Authority	No	1. Attachment 1, Row Number 4, Recommend deleting “at the same physical location” from the Verification condition. The first condition is recommended to read “Existing applicable unit that is equivalent to another unit(s),” Justification is that if a GO has units that are equivalent and meet the “sister” criteria, the standard does not need to be restricted to the same physical location. The GO identical equipment at different physical locations are still equivalent.
Response: The GVSDT thanks you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the “same physical location” requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the “same physical location” requirement is necessary.		
Cowlitz PUD	No	Cowlitz supports the comments put together by the NAGF SRT:1. We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has

Organization	Yes or No	Question 1 Comment
		identical equipment at differentphysical locations, they are equivalent. A sister is a sister independent of the physicallocation. As long as the equipment is identical, the concept should be allowed to applyregardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** 2. The SDT should consider moving the capacity factor exemption information found inAttachment 1, row 7 into the applicability section. The applicability section should allow anentity to be able to determine if the standard applies to them and be able to determine thescope of the facilities affected. It is best for those impacted to immediately know which unitsare in the scope and not have to realize the scope from a detailed study of the table ofAttachment 1. This would allow row 7 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comments. Please see responses above.		

Organization	Yes or No	Question 1 Comment
Wisconsin Electric Power Company	No	In Row 4, the use of 350 MVA as the cutoff for "sister unit" treatment is not reasonable. We propose the limit can be increased to 500 MVA without any adverse reliability impacts. **Response: Based on industry comments in a previous posting, the SDT raised the proxy unit cutoff from 250 MVA to 350 MVA. This cutoff will enable the inclusion of many steam units at sites with multiple and identical CC plants. The SDT believes that it has achieved stakeholder consensus on the current proxy unit MVA threshold.** Also, in Row 5, the allowable time for existing units to be verified following an indication of model problems should be 2 years, rather than 1 year, since existing legacy units may require additional resources to understand and resolve the issues. **Response: The language and timing in Attachment 1 have been vetted through several comment periods. The SDT believes that we have achieved stakeholder consensus on the current language and timing in Attachment 1 of the standard.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Oncor Electric Delivery Company	No	Oncor does not support the position that the Transmission Planner (TP) is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP.Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the Planning Authority (PA) only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides. **Response: Regarding the responsibilities assigned to the Transmission**

Organization	Yes or No	Question 1 Comment
		Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.
Response: The GVSDT thanks you for your comments. Please see responses above.		
PPL Corporation NERC Registered Affiliates	No	Since GO's typically do not have in-house expertise, they would either have to hire consultants to perform model verification or develop in-house expertise, including acquiring simulation software. Are such simulated models/software available today for this on the market? If not, has time been built into the implementation schedule for allowing such creation-it does not appear so? **Response: Generator Owners own the equipment. As such, Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners often work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner.** **Simulation software is available on the market, and there are consultants available with the necessary expertise to develop the required model data. Additionally, the SDT members believe the implementation plan provides ample time to develop the necessary capability. Significant portions of the power system are already performing routine model data**

Organization	Yes or No	Question 1 Comment
		validation. Also, the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units should be independent of the physical location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Independent Electricity System Operator	No	The long periods in Attachment 1 introduce too much risk: the modeling assumptions (used to derive operating security limits and to make other operating and planning decisions) do not reflect the actual performance of equipment. It would be better for the standard not only to establish the maximum period that Transmission Planners and Generators Owners to complete tasks but also to require the Transmission Planners to establish shorter periods when necessary to reduce the risk to reliability to an acceptable level. In Ontario, Generator Owners have 30 days to transmit the verified model, documentation and data to the Transmission Planner. Generator Owners are also required to indicate immediately following testing whether the installed equipment performed as expected. This

Organization	Yes or No	Question 1 Comment
		approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet requirements. Emerging from this process is the Generator Owner's conditional right to connect provided he meets an obligation to demonstrate the installed equipment behaves as well as assumed in the assessment process. In this way, the risk to reliability is reduced to an acceptable level as the exposure of the decision making process to flawed modeling assumptions is minimized. Experience in Ontario has shown that units that were expected to have essentially the same performance often show much larger differences than expected when tested. What seems like small or obscure differences to a Generator Owner can be critical to a Transmission Planner. **Response: The time periods in Attachment 1 have been vetted through several comment periods. The SDT believes that we have achieved stakeholder consensus on the current language and time periods in Attachment 1 of the standard.** Row 4 in Attachment 1 should be amended to require the amount of verification on "sister" units to be accepted by the Transmission Planner. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). The SDG believes that the verification conditions listed in Row 4 Attachment 1 are sufficient to assure that the Generator owner would be aware if there were differences between the units at the same location that would affect the model data.** Attachment 1 Row 4 that allows for new or existing units that does not include an active closed loop voltage or reactive power control function

Organization	Yes or No	Question 1 Comment
		should be changed. Given the size of the "applicable unit" virtually all units should be on voltage control unless specifically permitted by the Transmission Planner as is the case in Ontario. The adverse effects to reliability of not being on voltage control are well documented (Note1). The standard should be changed to put the onus on the Generator Owner of units not operating in voltage control to demonstrate continued operation in this mode does not have a material adverse effect on reliability. The standard should requirespecify the a process available for moving an "applicable unit" to closed loop voltage control when the Transmission Planner determines this is necessary.Note1: J.D. Hurley, L.N. Bize, C.R. Mummert C.R,The Adverse Effects of Excitation System Var and Power Factor Controllers, IEEE Transactions on Energy Conversion, Vol 14, No. 4, December 1999 **Response: The SAR for this draft standard calls for the verification of the generator's excitation system model data. Performance or operational requirements are beyond the scope of this standard. Note that the SDT assumes that you meant to refer to Attachment 1 Row 6, not Row 4.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Ameren	No	There appears to be a discrepancy between the language in the requirement R4 and its VSL compared to Row 3 of the Attachment 1. In the both requirement and VSL, a 180 day period is stated, while in Row 3 of Attachment 1, a 365 day period is stated.
Response: The GVSDT thanks you for your comments. R4 requires a Generator Owner to provide revised model data or plans to perform model verification within 180 days of changes to the equipment. If the Generator Owner chooses to plan to perform model verification, then when that model verification plan is submitted to the Transmission Planner, then in accordance with Requirement 2, Row 5 of Attachment 1 would specify that the Generator Owner has an additional 365 days to actually perform		

Organization	Yes or No	Question 1 Comment
the verification – including transmitting the verified model, documentation, and data to the Transmission Planner.		
Southern Company	No	We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT**

Organization	Yes or No	Question 1 Comment
		believes that we have achieved stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comments. Please see responses above.		
Cogentrix Energy	No	We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.

Organization	Yes or No	Question 1 Comment
		Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comments. Please see responses above.		
ISO-New England	No	Row 3 requires model transmittal "within 365 calendar days after commissioning the unit". It is not acceptable in terms of system reliability for a large unit to be operating on the system for 365 days after commissioning without a verified model. FERC approved ISO Tariff language also calls for provision of the model prior to Commercial Operation. The standard would not meet the requirements of the Tariff. Row 7 discusses capacity factor. The capacity factor reference has been removed from the requirements. If the capacity factor is still to be used this is unacceptable from a reliability standpoint. Large generators that have a low capacity factor will be required to operate under extreme conditions when the system is most stressed. A verified model should be provided regardless of capacity factor given this consideration.
Response: The GVSDT thanks you for your comments. This standard addresses model verification, not the submittal of preliminary design models. Model verification can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process. As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is		

Organization	Yes or No	Question 1 Comment
proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA. **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guideline, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 (footnote 2 in the current draft) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard.** **Also, the SDT does recognize that Regional variances can be considered if a Region desires to include additional unit MVA in this standard.**		
FirstEnergy	Yes	Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 7 should be a part of Applicability section 4.2 Facilities. The reader of the standard shouldn't have to get to the last row of an attachment to determine as to whether a unit is exempt or not.
Response: The GVSDT thanks you for your comments. The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Texas Reliability Entity	Yes	As TRE stated in previous comment periods to the standard, we disagree with using the 5% capacity factor (Attachment 1, Row 7) to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. We recognize this is somewhat alleviated by Requirement

Organization	Yes or No	Question 1 Comment
		R5, which now provides a method for the TP to request a model verification for a unit that has less than 5% net capacity factor if the unit's simulated response fails to match its measured response.
Response: The GVSDT thanks you for your comments. The SDT believes that there is negligible reliability to be gained by testing units with capacity factor of less than 5%. The added cost of testing is not justified. As you have noted, R5 does provide a method for TP to request model verification for a unit if the simulated response fails to match the measured response. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made to Attachment 1.Idaho Power Generator Owner- Suggest that "commissioning date" due date requirements be changed to "commercial operation date" to be consistent with other standards.
Response: The GVSDT thanks you for your comments. The language in Attachment 1 has been vetted through several comment periods. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.		
Duke Energy	Yes	We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units is independent of the physical location.
Response: The GVSDT thanks you for your comments. The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-		

Organization	Yes or No	Question 1 Comment
service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
Luminant	Yes	
pacificorp	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	
American Transmission Company	Yes	
American Electric Power	Yes	
Northeast Utilities	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Corporation and its affiliates	Yes	
Georgia Transmission Corporation	Yes	

2. **The GVSDT has revised the Applicability section 4.2.4 to make it clear that it applied to technically justified units that meet the NERC Registry criteria. It is emphasized that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. Do you agree with these revisions? If not, please explain in the comment area below.**

Summary Consideration: The majority of industry agreed with the revised language to make it clear that technically justified units were limited to units that meet the NERC Registry criteria thresholds and that "technical justification" is defined by demonstrating that the simulated unit or plant response does not match the measured unit or plant response. No modifications were made to the draft standard as a result of industry comments for Question 2.

Organization	Yes or No	Question 2 Comment
Tennessee Valley Authority	No	1. The GVSDT had good intentions by having a very short requirement. However, I am not sure what the intent is. A few more descriptive words would help greatly.
Response: Thank you for your review. Please note that the modification of language was made to the Applicability section.		
Exelon Corporation and its affiliates	No	Applicability Section 4.2.4 currently states "A technically justified2 unit that meets NERC registry criteria and is requested by the Transmission Planner." With the reference footnote stating "Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response."This intended applicability is confusing and implies that the Transmission Planner has the discretion to decide applicability if a previously exempted unit does not meet Transmission Planner decided criteria. Exelon suggests that this be deleted in its entirety. If the GVSDT intent is to pull in other generating units below the MVA threshold criteria based on Transmission Planner discretion, then that should be factored into Applicability Sections 4.2.1 through 4.2.3. In addition, if Section 4.2.4 is also written to negate an exemption based on Transmission Planner discretion then that provision should be factored into

Organization	Yes or No	Question 2 Comment
		Attachment 1 and not into the applicability section.
Response: The GVSDT thanks you for your comment. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."		
ACES Power Marketing Standards Collaborators	No	Because NERC and the Regional Entities do not maintain a public list of units that meet the "NERC registry criteria," it is impossible for the Transmission Planner to know for which set of units it may submit a technical justification per R5 and applicability section 4.2.4. The NERC ROP Appendix 5B, Statement of Compliance Registry criteria III.c.1, III.c.2 and III.c.3 each represent fairly "bright lines," where the TP can deduce which units meet these criteria. However, criterion III.c.4 is amorphous and notes on the page 11 of the document give NERC flexibility to deviate from the criteria anyway. Thus, we request that the drafting team either clarify that the "NERC registry criteria" in applicability section 4.2.4 is intended to mean criteria III.c.1, III.c.2 and III.c.3 in section III(c) of Appendix 5B - Statement of Compliance Registry Criteria or that the SDT work with NERC staff to determine how the TP may get a list of units that meet criterion III.c.4 and Note 1.
Response: The GVSDT thanks you for your comment. The intent of the verbiage is that all four criteria (III.c.1, III.c.2, III.c.3, and III.c.4) apply in combination with proof that the unit actual response does not match the model predicted response. In order to find out if a unit that is not otherwise meets the thresholds of III.c.1 – III.c.3 is included (per III.c.4), the team suggests that the applicable Transmission Planner can either check with the Region or NERC.		
Cowlitz PUD	No	Cowlitz is unsure if it is possible to accurately model generation such that modeling software will be able to predict actual plant response to a disturbance. The Standard may create a never ending circle of requests from the TP for improved modeling data. Cowlitz understands that modeling software is still in its infancy, and

Organization	Yes or No	Question 2 Comment
		more research and testing is needed to explore the boundaries between achievable modeling and where unrealistic goals exist.
Response: The GVSDT thanks you for your comment. Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.		
PPL Corporation NERC Registered Affiliates	No	It appears that without the word "and" in 4.2.4, this criterion of using NERC registration criteria would "trump" all the other interconnection requirements above. But, with the word "and" it indicates that any of the smaller registered units or blackstart resources would only be included in this standard if the Transmission Planner requires. The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.
Response: The GVSDT thanks you for your comment. The associated Requirement R5 does allow the TP a means to pursue		

Organization	Yes or No	Question 2 Comment
additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another. The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).		
Oncor Electric Delivery Company	No	Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. For MOD-026-1 Section 4.2.4, Oncor takes the position that it is the decision of the PA not the TP who determines the basis for NERC applicability.Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the applicability determination in Section 4.2.4, be the responsibility of the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comments. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.		
ReliabilityFirst	No	ReliabilityFirst believes there is a major disconnect/flaw between the Applicability Section (4.2. Facilities) and Requirement R2, part 2.1. This major flaw will create confusion on which generating units are required to be verified per the standard. ReliabilityFirst offers the following comments for consideration:1. Requirements R2, Part 2.1 - There is a clear disconnect between the Applicability section of the standard (i.e. individual units/plants greater than 100MVA - Eastern or Quebec Interconnections) and Requirements R2, Part 2.1 which requires"... Verification of an individual unit less than 20 MVA." Based on the Applicability section, units less than 20 MVA are not applicable under this standard. Furthermore, units under 20 MVA do not fall under the NERC Statement of Compliance Registry Criteria as criteria for registration purposes for GOs and GOPs. **Response: The intent of the SDT is to allow the model verification expert to use any combination of individual or aggregate models in the verification of plants. The SDT has modified the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both."** 2. Applicability Section 4.2. Facilities - ReliabilityFirst thanks the SDT for their justification for the 100 MVA threshold, but still believes that the Applicability should be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). Even though the 100 MVA threshold covers 80% of the connected MVA or greater for each Interconnection (in aggregate), depending on the geographic location (within the

Organization	Yes or No	Question 2 Comment
		BES), that value may be much less. For example, if there is a certain load pocket in which the majority of the connected generation is lest that 100 MVA, the dynamic models would not be required to be verified per this standard. Thus not having verified accurate dynamic models for this specific location could hinder the reliability of the BES. ReliabilityFirst recommends changing the Applicability section to be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). **Response: As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the excitation models and associated Reliability-based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification**

Organization	Yes or No	Question 2 Comment
		efforts. Footnote 4 (footnote 2 in the current draft) is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard. Also, the SDT does recognize that Regional variances can be considered if a Region desires to include additional unit MVA in this standard.
Response: The GVSDT thanks you for your comments. Please see responses above.		
Cogentrix Energy	No	The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that thedegree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified.It is also not clear how this comparison is to be made if the Facility did not have to provide aMOD-026 model in the first place. In any event the wording of the R5 Violation SeverityLevels should be modified to start the clock only after agreement has been reached that arequest is technically justified.
Response: The GVSDT thanks you for your comments. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another. **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes**		

Organization	Yes or No	Question 2 Comment
that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly withdraw its request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).		
Wisconsin Electric Power Company	No	We propose that the requirements for a "technically justified unit" must also include the technical reasons why the unit under consideration is critical to the reliability of the BES.
Response: The GVSDT thanks you for your comment. Regarding provision of a reason the unit is critical to reliability, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification.		
ISO-New England	No	This means that the Transmission Planner can only call for verification following a system event. It is counter to reliability to have to wait for an event to occur to then request verification. The footnote should be revised to include wording for the Transmission Planner to demonstrate an effect on the BES. Certain generators under 100 MVA could affect the BES and with this language verification could then take place.
Response: The GVSDT thanks you for your comments. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. **Regarding provision of wording for the Transmission Planner to demonstrate an effect on the BES, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard's base applicability.**		
FirstEnergy	Yes	1. Although we agree with the footnote definition for "technical justification", we would like the term "match" be replaced with "simulates or represents". We feel

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>that these terms give more interpretation when comparing.

2. While we agree that a threshold for unit verification is appropriate, we are not clear as to why there would be different threshold for each Interconnection. The SDT should include a Guidelines and Technical Basis section that explains the geographical differences.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comments.
1: The SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines “match” as something that is equal or similar to another.
2: The individual unit and aggregate plant ratings used in the applicability section were carefully derived for each Interconnection to capture validation of approximately 80% of the total installed base in that region. The selection of these applicability requirements intend to strike the most reasonable balance between managing the costs to perform tests and validation vs. ultimately assuring that the reliability of the Bulk System is not compromised due to poor models. This concept has been validated through industry comments from prior postings of the draft standard.</td></tr>
<tr><td>Manitoba Hydro</td><td>Yes</td><td>Although Manitoba Hydro agrees with the concept proposed, it is difficult or sometimes impossible to get an exact match between simulated and measured responses. The drafting team should allow for some engineering judgment (for example, if the responses are within 5-10% of each other, the model could be considered to be a reasonable representation).</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comments. Regarding the use of the term ”match,” there is no explicit requirement for quality of match between test and simulation in the determination of a technically justified unit. Regarding the second half of the comment beginning with a desire for acceptance criteria, the standard states “what is required” but not “how to accomplish what is required.” The SDT considered ways to quantify a method for evaluating how well the equipment’s measured response matches the model’s predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist.
Finally, in part, the SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines “match” as</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
something that is equal or similar to another.		
Dominion	Yes	Dominion agrees with this change; however, is concerned with the phrase “demonstrating that the simulated unit or plant response does not match the measured unit or plant response.” The use of the word “match” implies that the simulated response and measures response must be exact, when in fact this will not likely be the case. This language in section 4.2.4 (and other sections) should allow for acceptable variation so compliance can be properly achieved and demonstrated.
Response: The GVSDT thanks you for your comments. Regarding the use of the term ”match” to describe the expectations of model verification by the Generator Owner, there is no explicit requirement for quality of match between test and simulation in the determination of a technically justified unit. Regarding the second half of the comment beginning with a desire for acceptance criteria, the standard states “what is required” but not “how to accomplish what is required.” The SDT considered ways to quantify a method for evaluating how well the equipment’s measured response matches the model’s predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. **Finally, in part, the SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines “match” as something that is equal or similar to another.**		
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made in Section 4.2.4.Idaho Power Generator Owner- The phrase "units that meet the NERC Registry Criteria" has no meaning, since entities and not units are placed on the NERC registry. In addition, demonstrating that a simulated response does not match a measured response is not sufficient technical justification. Additional, technical justification should include demonstration that the different response materially impacts system studes. Additionally, allowing only one year for submission of test results following a technical justification is unreasonable, 5 or 10 years to match the initial implementation time period is more reasonable from the Generator Owner perspective for appropriately planning and scheduling the outage time and work.
Response: The GVSDT thanks you for your comments. The SDT believes the language regarding units that meet NERC Registry		

Organization	Yes or No	Question 2 Comment
(emphasis) "Criteria" is clear – as criteria is not referring to entities that may (or may not) be required to register in the NERC Registry as a Generator Owner. Regarding provision of a reason the different response materially impacts system studies, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard's base applicability. Also, the SDT believes one year is sufficient time to verify the model. Online step in voltage tests or ambient monitoring are techniques which do not require unit outages to implement.		
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Yes	In general, Ingleside Cogeneration LP believes that a good working relationship between the Generator Owner and Transmission Planner includes a reasonable justification for any request that requires time and expense on the part of the other.
Response: The GVSDT thanks you for your comment.		
Texas Reliability Entity	Yes	Should Blackstart units have a specific inclusion as an "applicable unit", regardless of capacity factor or "technical justification"?
Response: The GVSDT thanks you for your comments. The SDT has not included Blackstart units in the base Applicability.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Luminant	Yes	
pacificorp	Yes	

Organization	Yes or No	Question 2 Comment
Southern Company	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	

3. Do you have any other comment, not expressed in questions above, for the GVSDT?

Summary Consideration:

The following modifications were made to the standard in response to industry comments to Question 3:

In the Effective Date section 5.3, the word “thirty” after the word “quarter” was inserted in the standard by mistake. As such, the SDT removed the word “thirty.”

The wording, “… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities …” in Section 5.1 was moved to right after “approved by applicable regulatory authorities …” And that same wording was moved to right after, “… following applicable regulatory approval …” in Sections 5.2 to 5.4. Also, the same phrase was appended to each of the four bullets in the Effective Dates Section, “In those jurisdictions where regulatory approval is required:” of the Implementation Plan right after, “… following applicable regulatory approval …”

The SDT has clarified Section 4.2.4 in the Applicability Section as follows: “A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner.”

The SDT has refined the applicable portion of Part 2.1 to read: “Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both.” This ties the requirement to the applicability of the standard per stakeholder request.

Refined sub part 2.1.2 to read: “Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed).”

Clarified that the response by the Transmission Planner to the Generator Owner concerning the results of testing the model useability is required to be a written response (R6). Also, for ease of reading, moved the last sentence in the requirement to after the parts.

Revised the first sentence in R1 to read: “Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request.”

Included the term “impedance compensation” to Footnote 1 in the description of what constitutes a excitation control system for synchronous machines.

Organization	Question 3 Comment

Organization	Question 3 Comment
ACES Power Marketing Standards Collaborators	(1) Thank you for modifying the applicability section. It is greatly improved and is much clearer than the previous version. However, we believe there are a few additional minor refinements necessary. First, generators can be and are part of the Bulk Electric System. Thus, we suggest changing “Facilities that are directly connected to the Bulk Electric System (BES)” to “generation Facilities that are part of the Bulk Electric System.” Otherwise, there might be some confusion if the drafting team intends to draw in generators that are not part of the BES. Second, we find the wording “will be collectively referred as an ‘applicable unit’ that meet the following” confusing. We think the intent was to clarify that an applicable unit is one that is part of the BES and meets criteria established in section 4.2.1, 4.2.2, 4.2.3, and 4.2.4. However, we think the inclusion of the “will be collectively referred as an ‘applicable unit’” is superfluous. Because the section is the applicability section, we think this language could be struck for clarity and the applicable units will be understood to mean those that meet the criteria in section 4.2. As an alternative, the drafting team could explain in a footnote what they mean by the term applicable unit. Third, with the two proposed changes, we think the final wording of section 4.2 after the opening clause should be “generation Facilities that are part of the Bulk Electric System (BES) that meet the following criteria:”. **Response: The SDT believe that the term “directly connected to the Bulk Electric System” is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria. The reason for utilizing the term “applicable unit” is that it is used in other portions of the standard and allows a simple reference to the base Applicability for each Interconnection.** (2) In requirement R2, please change “for each applicable unit” to “for each of its applicable units.” This is the previous wording and is more correct. The current wording literally says that the GO must provide a verified model for each applicable unit including those it does not own. After all any unit that meets applicability criteria including those owned by other GOs would be an applicable unit. **Response: The SDT believe that the use of the phrase “for each applicable unit” being placed in a sentence immediately after the phrase “Each Generator Owner shall provide” clearly conveys the intent that the applicable units being referenced are those which belong to each Generator Owner. Also, note that the term “applicable unit” is defined for the content of this standard in**

Organization	Question 3 Comment
	the Applicability section. (3) Please specify in M1 that a Transmission Planner may also provide an attestation that no such request was received if this is the case. Use of attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set in the use of attestations in measures in FAC-003-2 M1 and M2. **Response: As you stated, compliance recognizes that an attestation is an acceptable form of evidence. As such, including that in the Measures is repetitive.** (4) We continue to believe that the examples provided in the comment form should be included in the standard. Please create an Application Guidelines or Guidelines and Technical Basis section in the standard and add them. This has become common practice with developing standards. We do not understand why the drafting team would not want to retain such information that helps readers understand the standard and that has already been developed. Furthermore, it would make it easier for commenters to see what has changed in the examples because a red-line of the standard is required. Because the examples were contained in the comment form this time and during the previous posting, it is not easy to deduce the changes because there is no red-line. If the examples are not included in the standard, please provide more explanation than was provided during the last response to comments which was that it is not appropriate to include the examples. We do not understand why it is not appropriate. **Response: The examples provided were for clarification, and the SDT does not believe that all possible scenarios are considered. The SDT does not believe the examples are appropriate for inclusion in the standard itself. Also, the sections that you referred to as being an appropriate location to include the examples are not part of this standard's format. We believe that majority of stakeholders do not have a desire to include these examples in the standard.** (5) We disagree with the need to retain the latest model verification evidence under Requirement R2 and M2. First, this is not consistent with the Section 3.1.4.2 of Appendix 3c to the NERC Rules of Procedure section which states that the audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since the audit cycle for a GO is six years and the model verification period is 10 years, the GO will have to retain data past its prior

Organization	Question 3 Comment
	audit period. Furthermore, the auditor will have already had an opportunity to review the model verification data during the last audit. Presumably, if they did not find any compliance violations, there should not be a need to review this data again. Thus, the data retention should not exceed the six year audit cycle. **The SDT believes that once the recurring 10-year periodicity is established, that the Generator Owner has to maintain records regarding the last verification to be able to demonstrate that they conducted a valid verification within the last 10 years. As written, this follows the Data Retention guidelines. The alternative is to shorten the periodicity to six years. However, as confirmed by industry comments in prior postings, the SDT believe that the 10-year periodicity has overwhelming industry consensus.** (6) How will mothballed units be handled in Attachment 1? If a mothballed unit is returned to service which row in Attachment 1 applies? What if the unit was mothballed before the effective date and returned to service after all stages of the effective dates? What if it was mothballed after an initial verification? How does this affect the next verification date? **Response: If the unit was mothballed before the effective date of the standard, upon coming out of retirements, Row 3 would be applicable. In all cases, after the initial verification, at a minimum, the 10-year periodicity would apply. Thus, if a unit was mothballed for years 5 – 7, the model would still need to be verified with the documentation and data to the Transmission Planner at year 10.**
Response: The GVSDT thanks you for your comments. Please see responses above.	
Ameren	(1)We request that papers listed in the references section of the standard are made readily available on the NERC website. **Response: The papers are readily available as documented in the references. Due to copyright limitations, many of the documents cannot be made available on the NERC website.** (2)There appears to be an extra word “thirty” in both redline and clean versions of the standard under section 5.3 of the Effective Date section of the draft standard.

Organization	Question 3 Comment
	Response: The extra "thirty" has been removed in the current draft of the standard. (3)As we understand, part of R1 is for the Transmission Planner to provide instructions on how to obtain the list of acceptable model types for use in dynamic simulations. In this regard, we ask the SDT if this would preclude the use of user-written models? **Response: The standard does not preclude user written models however the model must be on the list approved by the Transmission Planner.** (4)We still have serious concerns about compliance with new MOD-026-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect. We appreciate the SDT considering our comments on this issue in the last draft, but we still disagree about the potential conflicts for the following reasons:(a)The reporting requirements to comply with MOD-012 are dependent upon the data requirements and reporting procedures put in place by their Regional Entity as mandated by MOD-013. This does not provide consistency across the country. (b)We take data reporting under MOD-012 very seriously and incorporate testing in our program to ensure the data is accurate. Consequently, our reporting and compliance with MOD-012 does involve generator testing on a 5 year basis. (c)Any GO that has implemented a MOD-012 compliance program that involves testing that cannot perfectly synchronize with the 10 year testing in this draft of MOD-026 will have a significant burden in scheduling generator testing to satisfy both standards.(5)We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal requirements within MOD-026. This will synchronize the reporting and verification requirements and help minimize the resource burden of compliance with both efforts. At the same time it will create consistency across the country. **Response: MOD-012 and MOD-013 contain data submittal requirements that require submission of the latest dynamic model data for generator, excitation system, voltage regulator, power system stabilizer and turbine-governor. MOD-026 requires model verification including submittal of the verified excitation system dynamic model and data.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Idaho Power Company	1) Technical Justification of units based solely on a simulated response not matching recorded

Organization	Question 3 Comment
	response is insufficient. Technical Justification needs to include evidence that the difference in response has a material effect on the conclusions of the relevant system studies. **Response: Regarding provision to include evidence that the difference in response has a material effect on the conclusions of the relevant system studies, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard's base applicability.** 2) Requiring each Transmission Planner to maintain a list of acceptable models, and then requiring Generator Owners to submit data according to those models is unreasonable. The list of acceptable models needs to be at least regional, if not continent-wide. In addition, some required longevity needs to be specified to allow Generator Owners to appropriately plan and perform the verification work. **Response: Since the Transmission Planner is the user of the models, the models must be acceptable to the Transmission Planner in order to be deemed useful. The list of models in the vast majority of the time will be models included in major manufacturer dynamic simulation software vendor libraries and they have a high correlation with other dynamic simulation software vendor model libraries and those developed via IEEE.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Texas Reliability Entity	1) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. **Response: The SDT believe that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria.** 2) TRE recommends changing to "Planning Authority or Transmission Planner" in the Functional

Organization	Question 3 Comment
	Entities in Section 4.1.2 instead of "Transmission Planner". This change should be duplicated in the requirements. The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. **Response: The reporting structure of the standard has been vetted through multiple comment periods and the GVSDT believes that the Transmission Planner is the appropriate entity. The GVSDT believes that we have achieved stakeholder consensus on the current language of the standard.** 3) The timelines are generally too long, which will result in stale, incorrect and generic data being utilized in modeling systems. Consider shortening timeframes. **Response: The timelines contained in the standard has been vetted through multiple comment periods and the GVSDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Wisconsin Electric Power Company	1. In 4.2.1.2, the use of the term "directly connected at a common BES bus" suggests that wind farms are not applicable facilities, since wind generators are typically directly connected to a non-BES bus (e.g. 34.5 kv). We suggest that the applicability to wind farms be clarified more explicitly. **Response: The SDT believe that the term "directly connected to the Bulk Electric System" is appropriate as that is the verbiage used in the Statement of Compliance Registry Criteria.** 2. In R1, the present wording allows for the TP to provide only one of the three types of data, even if the GO requested all three. We suggest removing the wording, "one or more of". **Response: Based on your comment, the SDT revised the first sentence in R1 to read: "Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request:"** 3. In R1, the present requirement is for the TP to provide instructions to the GO on how to obtain the acceptable models and associated block diagrams and data. We believe that since the TP is very familiar with this data and the GO may not be, it is far simpler and efficient for the TP to provide the

Organization	Question 3 Comment
	actual data on request, not just the instructions on how to obtain it. **Response: Transmission Planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner. However, the software manufacturers have indicated that they will make accommodations so that Generator Owners without software licenses can receive the block diagrams and data sheets.** 4. In R2.1.1, the GO is required to have documentation comparing the "model response" to the "recorded response", in this case Voltage vs. Time. First, to determine the model response requires the ability to run dynamic studies. Generally the GO does not have the simulation capability or the subject matter experts required to perform dynamic system studies. It would seem that the intent of this requirement is that the GO must expend considerable resources to gain this capability, either internally or by other means. Is this the intent of the SDT? **Response: Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired - or the Generator Owner can enter into agreements with its Transmission Planner, though the Generator Owner will still be responsible from a compliance perspective. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased.** 5. In R3, the requirements for the written response to the TP need clarification. The term "either" would suggest there are two possible responses. However, there appear to be three possible responses. We suggest there needs to be a 4th possible response option for the GO, for the GO to

Organization	Question 3 Comment
	initiate contact with the TP to schedule a meeting to discuss the technical issues with the model. The necessary collaboration between the GO and TP to understand the model deficiencies will require time, thus may require more than the 90 days to reconcile the model issues. 120 days is suggested. **Response: The SDT believes that the sentence containing the word "either" clearly lists the three written response options afforded to the Generator Owner. Merriam-Webster dictionary defines "either" when used as a conjunction as, "Used as a function word before two or more coordinate words, phrases, or clauses joined usually by or to indicate that what immediately follows is the first of two or more alternatives." The SDT believes that 90 days is sufficient time to for the Generator Owner to discuss model issues with the Transmission Planner. The SDT believes all parties will be equally motivated to work through model verification issues.** 6. In Section 5 Effective Dates: The considerable time and resources needed to get up to speed with model verification suggests there needs to be more time allowed in the earlier phases of the compliance timeline. We suggest using 20 percent in 4 years, 40 percent in 6 years, and 100 percent in 10 years. **Response: The SDT believes the effective dates have been well vetted in previous postings and that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Dynegy	1. It's not clear what the difference is between R3 and R5. Suggest combining these into one Requirement. MOD-027-1 which also requires model validation does not have a Requirement similar to R5.2. Requirement 2.1.1 does not state how much of a step change is required when testing the exciter controls. A commonly used step is 2% but this is not clear.
Response: The GVSDT thanks you for your comment. The peer review type activities in R3 are for units which have been verified per the standard, or the verification process is on-going, but there are potential issues regarding that verification process. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response for units that are above the threshold in the current NERC Registry Criteria but	

Organization	Question 3 Comment
	below the standard's base Applicability MVA thresholds. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner." Regarding step change magnitude to test the exciter controls, the SDT believes that the method used to verify the model should be determined by those doing the model verification. The testing expert will determine the voltage excursion magnitude to use during testing and other details regarding how to do the test.
Essential Power, LLC	1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed

Organization	Question 3 Comment
	(e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. **Response: Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.** 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed “usable” by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner

Organization	Question 3 Comment
	expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard through the previous comment periods. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's done.** 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard through the previous comment periods.** 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. **Response: The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of**

Organization	Question 3 Comment
	the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another. **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).** We propose that the requirements for a "technically justified unit" must also include the technical reasons why the unit under consideration is critical to the reliability of the BES. **Response: Regarding provision of a reason the unit is critical to reliability, R5 has undergone several modifications around this point. The SDT believes the existing R5 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification.** 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree

Organization	Question 3 Comment
	of impact on system response and the expected duration are needed. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard.** 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** 7. Sub-requirement 2.1.4 is not clear - is this data the model block diagram and its parameters? If so, simply state that. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 8. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service).**

Organization	Question 3 Comment
	9. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted. **Response: The SDT decided to place all the scenarios that effectively "exempt" otherwise applicable units in Attachment 1 for clarity. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Cogentrix Energy	1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component modelsare inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility)moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15,2012 FFT Order to propose specific

Organization	Question 3 Comment
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Organization	Question 3 Comment
	Response: The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another. **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified". If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria).** 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes thatalter the system response is too vague, despite the attempted clarification in footnote #3,since many activities can have some degree of impact as noted above. Reportablethresholds regarding degree of impact on system response and the expected duration areneeded. **Response: The SDT believes that we have achieved stakeholder consensus on the current**

Organization	Question 3 Comment
	language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing unitsthat meet the NERC registry criteria but are smaller than the MVA size specified in theapplicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** 7. Sub-requirement 2.1.4 is not clear - is this data the model block diagram and itsparameters? If so, simply state that. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 8. We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has identical equipment at differentphysical locations, they are equivalent. A sister is a sister independent of the physicallocation. As long as the equipment is identical, the concept should be allowed to applyregardless of location. **Response: The SDT notes the general agreement among industry with using the proxy unit approach. The SDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g., requirement for PSS in-service).** 9. The SDT should consider moving the capacity factor exemption information found inAttachment 1, row 7 into the applicability section. The applicability section should allow anentity to be able to determine if the standard applies to them and be able to determine thescope of the facilities

Organization	Question 3 Comment
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Response: The GVSDT thanks you for your comment. Please see responses above.	
FirstEnergy	1. FE believes that Requirement 6 in an un-necessary requirement that the Transmission Planner must respond within 90 calendar days that the model is usable. The Transmission Planner should only respond if the information is not usable. We suggest that this requirement should be in a negative perspective and offer the following revision:R6. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 6.1 through 6.5), and shall include a technical description if the model is not usable that includes (but not limited to) the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 6.1. The excitation control system or plant volt/var control function model fails to initialize during a dynamic simulation along with suggested areas for investigation, 6.2. A listing of parameters that fail the Transmission Planner's data checks, 6.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 6.4. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria.6.5. The excitation control system or plant volt/var control function model submitted by the Generator Owner is either a user defined model or a model that is not acceptable for use in the Transmission Planner's Regional Reliability Organization footprint. **Response: The SDT believes that the level of specificity in R6 sub parts is adequate as drafted. Based on your and another commenters input, the SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at**

Organization	Question 3 Comment
	the next to last use of the word "usable" and we moved that last sentence to after the three criteria. The last sentence now reads: If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. Also, for ease of reading, the SDT moved the last sentence in the requirement to after the parts. 2. For clarity, Requirements 3 and 5 are confusing and seems to be the same. We feel the that R5 can be removed from MOD-026. This will also be consistent with the requirements of MOD-027. **Response: The peer review type activities in R3 are for units which have been verified per the standard, or the verification process is on-going, but there are potential issues regarding that verification process. The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response for units that are above the threshold in the current NERC Registry Criteria but below the standard's base Applicability MVA thresholds. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Alberta Electric System Operator (AESO)	1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger. **Response: As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the excitation system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the**

Organization	Question 3 Comment
	exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA and kV thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. **Response: The SDT believes that re-verification every 5 years is unnecessary. This position is supported by an overwhelming majority of comments received from the industry. As such, the SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 3. Requirement R4, as written it appears owners of generating units that plan to change out the excitation control systems are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change. **Response: This standard addresses model verification, not the submittal of preliminary design models. Model verification can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
ExxonMobil Research and Engineering	A stated purpose of Generator Verification is “to ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.” Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets’ capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk

Organization	Question 3 Comment
	electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load's process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load's production schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same.
Response: The GVSDT thanks you for your comment. The GVSDT has used a subset of the registry criteria to identify applicable Facilities. If a unit meets the sub set of the registry criteria it is obligated to comply with the standard.	
Independent Electricity System Operator	a. No explicit NERC performance requirements for excitation system are a weakness. In Ontario, generating units are required to materially help regulate voltage as the Transmission Planner sets performance requirements for upper and lower ceilings, voltage response time, and stabilizer characteristics. This standard in its present form allows generators to continue to not materially help regulate voltage provided the documentation submitted to Transmission Planner is consistent with this lack of performance. **Response: The SAR for this draft standard calls for the verification of the generator's excitation system model data. Performance or operational requirements are beyond the scope of this standard.** b. In Ontario, experience has been that the models typically used by the Transmission Planner are not commonly employed by Generator Owners. The standard recognizes this in R1 by giving the obligation to the Transmission Planner to provide model block diagrams or data sheets to the Generator Owner. As the Transmission Planner may be unaware of practicable constraints on a unit and the Generator Owner may not be familiar with the reliability models; both parties must reach

Organization	Question 3 Comment
	an accommodation on the details to verify the model. R2 should be changed so the Generator Owner is required to provide a model that has been verified by a method accepted by the Transmission Planner. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes that the method used to verify the model should be determined by those doing the model verification, and that the transmission planner should only be concerned with the result, which is a correct model for the equipment. The testing expert will determine the voltage excursion magnitude to use during testing and other details regarding how to do the test. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of "match" does not exist. The focus is solely on "what" is required, not "how" it's done.** c. The measured performance of the OEL, UEL, stator current limiter or any other automatic control system that alters the behaviour of the excitation system should be part of the Generator Owner submission to the Transmission Planner as limiter performance can affect reliability decisions. No limiter that imposes more restrictive limits than the required short term field and armature current requirements in ANSI/IEEE 50.13 should be implemented without the Transmission Planner's approval. **Response: The SAR for this draft standard calls for the verification of the generator's excitation system model data. Performance or operational requirements are beyond the scope of this standard.** d. The concept of "applicable unit" should be extended to include static var generators and similar devices. All facilities with an excitation control system and more than 100 MVA of capability should fall under this standard. **Response: Static Var generators and other similar devices, such as Synchronous condensers, are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements**

Organization	Question 3 Comment
	would not make sense. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. e. Changes to the generator (e.g. rewinds or active power output increases) will affect excitation system performance. The standard should require re-testing following other modifications that the Transmission Planner can show with simulations will require modifications to the excitation system to improve reliability. For example, turbine replacements often provide increased active power capability. At higher levels of active power, the excitation system can materially change without coordinated changes to over-excitation limiters. **Response: For the example given, increased active power would require an alteration in the Interconnection Agreement – and similar to a new unit, the transmission entity should be able to dictate terms which state activities that must be completed so that the increase in power can be reliably delivered to the transmission system – including any protection and/or limiter setting changes and any needed re-verification of models. The SDT believes that the vast majority of scenarios that could cause an alteration of excitation control system response changes that should drive a re-verification of models are captured in R4 and the corresponding footnote number 5. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** f. R2.1 should be amended (see below) to add flexibility to include other practical combinations of units to be used for verification. For example, it can be more practicable to test wind and solar installation one feeder at a time but this is not allowable with the standard in its present form. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA

Organization	Question 3 Comment
	(gross nameplate rating) may be performed using either an individual unit, a combination of units, or plant aggregate model(s). **Response: The SDT thanks you for your comment. Based on your comment, the SDT has modified the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both."** g. In Ontario we face resistance when our standards exceed NERC requirements. Would it be possible for the SDT in its response to offer its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, if none of our comments can be adopted into the standard, we would appreciate responses such as: "In the opinion of the SDT, having more applicable units on closed loop voltage control, reducing the time to transmit verified information to the Transmission Planner, having specific excitation performance requirements, expanding verified information to include limiters and other devices that affect excitation system performance, and making the requirements in this standard applicable to wider range of equipment are all practices that will tend to improve reliability." Or "In the opinion of the SDT, the requirements in this standard are not intended to preclude continuing or implementing more stringent Transmission Planner requirements "This type of response would help us to continue to augment continent-wide standards with additional requirements to maintain reliability in our part of the interconnection. **Response: The SDT does believe that the requirements in this standard provide a floor and that individual regions or transmission entities, through venues such as interconnection agreements, can implement more stringent requirements. Unfortunately, the SDT scope is limited to drafting a national standard.** h. We appreciate the SDT's effort to implement our proposed language changes to remove a potential conflict with the Ontario regulatory practice respecting the effective date of implementing approved standards. The added language, unfortunately, was not added at the appropriate places. We suggest the SDT to move the wording " , or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," in Section 5.1 to right after "approved by applicable regulatory approval", and move that same wording to right after "following applicable

Organization	Question 3 Comment
	regulatory approval" in Sections 5.2 to 5.4.Also, the same phrase should be appended to each of the four bullets in the Section "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after "following applicable regulatory approval." **Response: We have made the requested edits.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
South Feather Power Project	Applicability section 4.2.2.2 describes an Individual Generating Plant as consisting of multiple generating units that are directly connected at a common BES bus with a total capacity greater than 75 MVA. It would help if there was a proximity element to the definition of "Individual Generating Plant." My question/comment comes from the fact that I have three single unit powerhouses with a combined total capacity greater than 75 MVA connected to a single 115 kV radial line, with several miles of transmission line separating each unit from the other, but the radial line (which is owned by another entity) ultimately terminates at a single (common) point on a BES bus. Attached to this same radial transmission line are a distribution substation and another entity's small hydro plant, so it is not clear how this common point on a BES bus would be characterized.
Response: The GVSDT thanks you for your comment. The SDT believes that the current language is clear. Regarding your specific circumstance, if the three single unit powerhouses are interconnected to a common BES bus with an aggregate capacity greater than specified in the Applicability section for an individual generating plant, then that plant does meet the draft standard's threshold. If the three single unit powerhouses are not connected to a common bus, but are tapped at buses on various locations of the radial line, then their Applicability would be based on the individual unit thresholds in the Applicability section of the draft standard.	
Cowlitz PUD	Cowlitz supports the comments put together by the NAGF SRT:1. The standard is based on the assumption that it is possible to tune the acceptable modelscited in R1 such that their predictions will match actual voltage and reactive powerresponses to system Disturbances. The yet-to-be-defined acceptable models may not becapable of achieving this goal, however, because standard excitation component modelsare inadequate to predict with high fidelity the generation system

Organization	Question 3 Comment
	response that is thesubject of MOD-026-1. Such models do not take into account, for example, equipmentthermal capability limitations and the capping of reactive power output to respect aux busvoltage limits.The SDT is therefore asking for a considerable advancement in the excitation modelingstate of the art, to be undertaken in parallel by the owners of every generation unit in NorthAmerica. This is a doubly daunting task in that GOs often do not have any dynamicmodeling software or expertise, much less the ability to invent something new, because thepresent approach to the subject is that GOs just provide the values of input parameters tothe TP, which owns and runs models.Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility)moreover do not have and cannot obtain information on the system outside the plant batterylimits. This circumstance renders them unable to model the plant-T&D interactionsassociated with Disturbances, and independent GOs may therefore forever remain unable todevelop model results that closely match actual Disturbance responses.The approach being taken in MOD-026-1 is consequently viewed as being technicallyinfeasible for the present state of the art as well as unjustified in light of FERC's March 15,2012 FFT Order to propose specific standards or requirements that should be revised orremoved [or not enacted in the first place] due to having little effect on reliability or becauseof compliance burdens.The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF),equipment OEMs, and modeling services vendors to develop the right tools for the job, andput the new models through trial runs at several plants. These trials should be limited todata-collection means that can be non-invasively employed (e.g. online voltage stepresponsetests, low-load rejection during normal stop events), and should lead to definitionof specific testing means for definition of specific model parameters. The SDT should thenput out for voting a standard requiring TOPs to own and run these models, and requiringGOs to provide them the appropriate input data, developed via the non-invasive meansstated above. **Response: Excitation control system model verification is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the**

Organization	Question 3 Comment
	transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. 2. There is presently no definition of the voltage excursion magnitude and intensity or therecording instrumentation sampling rate required for a valid verification event. There arealso no specifics regarding how closely the model must match the recorded response or forwhat period of time, just a requirement that it be deemed “usable” by the TP. The SDT isasking for a blank check, and we cannot agree to regulations for which it is impossible tosay at the time of balloting whether or not compliance can be achieved, let alone in afashion that is justified per the FERC order cited above.Perceived shortcomings in these respects would presumably trigger the TransmissionPlanner expression of concern described in R3, but it would be better to establish the rulesup-front rather than addressing the matter only after a GO has attempted to comply withMOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make itinto the standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it’s**

Organization	Question 3 Comment
	done. 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," therotational inertia divided by MVA rating, since this is the parameter of interest for stabilitystudies. Either way, the obligation to conduct testing in this respect should be waived forunits having an OEM-developed value and no modifications to the rotating components,since rotational inertia can be identified more precisely via calculation than by clocking apost-trip over speed excursion. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that thedegree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified.It is also not clear how this comparison is to be made if the Facility did not have to provide aMOD-026 model in the first place. In any event the wording of the R5 Violation SeverityLevels should be modified to start the clock only after agreement has been reached that arequest is technically justified. 6. **Response: The associated Requirement R5 does allow the TP a means to pursue additional model information if the model's predicted response does not match the actual equipment response. Models do exist for these units through the processes defined in MOD-012 and 013, though they may not have been verified. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Regarding the desire for criteria for mismatch, the standard states "what is required" but not "how to accomplish what is required." The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response for this and other requirements. However, a generally accepted technique or criteria for making this quantitative assessment does not exist. The SDT believes use of the term "match" is appropriate because the Webster's dictionary defines "match" as something that is equal or similar to another.** **The SDT believes the existing wording of the VSL for R5 regarding when the clock starts is fair for all stakeholders and provides a well-defined and measurable initiation point. Also, the SDT**

Organization	Question 3 Comment
	believes that the activities described in R5 will rarely occur. One reason why this will rarely occur is because the only units that could be subjected to this requirement are those which are above the thresholds in the NERC Registry Criteria but are below the thresholds specified in the Applicability (Section 4). When they do occur, if the Transmission Planner obtains the recording of an event and subsequently perform a post mortem analysis and the results show that the response of the actual equipment does not match the predicted response of the model, the SDT believes that there will be no doubt that the unit fits the requirement of being declared "technically justified." If a fundamental error occurs that is discovered in the process, then the Transmission Planner will have no choice but to promptly remove their request (i.e., as there is not sustainable evidence that the unit meets the "technically justified" criteria). 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes thatalter the system response is too vague, despite the attempted clarification in footnote #3,since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard.** 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** 7. Sub-requirement 2.1.4 is not clear - is this data the model block diagram and its parameters? If so, simply state that. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved**

Organization	Question 3 Comment
	stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comments. Please see responses above.	
Exelon Corporation and its affiliates	Exelon again reiterates that the Standard should specifically define the acceptance criteria. The current draft (draft 4) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not “usable”, if there are technical concerns with the verification documentation, or if the model response did not match the recorded response to a transmission system event. This written response is to contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification. It appears from previous comments of the GVSDT that the Generator Owner has final say on the model and the GVSDT has previously responded "that the standard is written so that the Generator Owner “owns’ the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model’s predicted response.” While Exelon agrees with this statement; Exelon again requests that this language be clearly articulated within the body of the Standard or that definitive acceptance criteria be added to the Standard.
Response: Thank you for your comment. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it is done. Finally, the SDT has drafted the standard is such a manner that the Generator Owner is the “owner” of the model.	
American Transmission Company	For Requirement 6, ATC recommends the wording at the end of the requirement to read “that includes how any of the following criteria are not met:” because the existing wording does not express that the criteria are not met when the model is not usable.

Organization	Question 3 Comment
Response: Thank you for your comment. The SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at the next to last use of the word "usable." The second sentence now reads: The TP will provide a technical description of why the model is not usable.	
CenterPoint Energy	In R6, CenterPoint Energy recommends changing 90 days to 180 days for a Transmission Planner to notify the Generator Owner that a model is usable or is not usable. Such a change will allow time for model verification through the various regional processes for generator data submittals and dynamic planning case building.
Response: Thank you for your comment. The SDT believes that 90 days is sufficient time for the Transmission Planner to notify the Generator Owner, and that we have achieved stakeholder consensus on the current language and timing specification contained in the standard.	
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)	Ingleside Cogeneration LP agrees that the ability for Transmission Planners to effectively model and simulate actual system response to voltage transients can lead to reliability improvements. In addition, the technical veracity and implementation time frames in the latest version of MOD-026-1 are far improved over previous versions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed:1) All requirements for recurring tests (R2) must contain language that focuses on the strength of the validation process - not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed - even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation.2) The Compliance organization needs to be engaged in the development process so that industry

<table>
<tr><th>Organization</th><th>Question 3 Comment</th></tr>
<tr><td></td><td>stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects.</td></tr>
<tr><td colspan="2">Response: The GVSDT thanks you for your comments. Your issues relate to the "Find, Fix and Track" process that was most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states: "Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months." This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of MOD-026 are to simply verify the model and provide that model to the Transmission Planner. Under this standard, the responsible entity either performed the verification and reported it or they didn't. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.</td></tr>
<tr><td>Oncor Electric Delivery Company</td><td>Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. There are defined NERC processes outside the GV SDT effort where entities can request a regional variance. Alternatively, the Transmission</td></tr>
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Organization	Question 3 Comment
Planner could delegate the responsibility to another such as its Planning Authority	
Southern Company	Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. **Response: Thank you for pointing out the need to include further clarification. The SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner."** Sub-requirement 2.1.4 Is not clear - is this data the model block diagram and its parameters? If so, simply state that.SCS agrees with the modifications to the Periodicity Table as they both simplify and clarify the periodicity. **Response: The phrase "model structure" refers to a block diagram without parameter values, thus the SDT feels like the language in R2.1.4 is clear. The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Thank you for your positive comment regarding the modifications to the Periodicity Table.**
Response: Thank you for your comment. Please see responses above.	
Florida Municipal Power Agency	Related to our comment on MOD-025, if synchronous condensers are only owned by TOs, then the excitation system of a synchronous condenser would not be verified in MOD-026 because it is only applicable to GOs. FMPA recommends that synchronous condenser excitation systems should be verified through the same process, and as a result, if a synchronous condenser is owned by a TO, then a TO should have applicability to it only for excitation systems on synchronous condensers it may own.
Response: The GVSDT thanks you for your comment. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT	

Organization	Question 3 Comment
believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.	
Manitoba Hydro	Section 2.1.2 - Manitoba Hydro suggests revising the text to read as follows: Manufacturer, model number (if available), and type of excitation control system and the plant volt/var control function (if installed). **Response: Based on your comment, the SDT realized that the sentence could be refined and as such refined the sentence in sub part 2.1.2 read: "Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed)."** R2.1.4. - Manitoba Hydro proposes that only the text of "Model structure and data for the excitation control system" is kept. An excitation control system consists of generator and excitation system as per IEEE 421.1 and 421.5. 4.2 – **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. Note that the SDT did add the term "impedance compensation" to Footnote 1 in the description of what constitutes a excitation control system for synchronous machines – the SDT believes that calling out "impedance compensation' is important as determined in its role in previous events.** The language immediately preceding the bullets is unclear (i.e. 'that meet the following' should possibly be reworded as 'provided they meet the following'). **Response: The SDT has modified the applicable portion of Part 2.1 to read: "Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section**

Organization	Question 3 Comment
	4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both." R1 -This requirement would be clearer if rewritten as 'Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner: **Response: The SDT did modify R1 so that it now reads: Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request:** 'General Comment - Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? **Response: The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes that the calculation of the percentages will be trivial, and will allow Generator Owners flexibility as compared to a "number " or "percentage" of units approach.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Northeast Power Coordinating Council	Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. **Response: The percentages in the Effective Date section refer to the entity's applicable unit gross MVA for each Interconnection. The SDT believes this is a clear designation that the thresholds are determined by the percent of unit gross MVA and not by the number of devices. This does mean that the total applicable unit MVA per Interconnection, as specified in Section 4.2 (Applicability / Facilities) will have to be determined by the Generator Owner. The SDT believes that we have**

Organization	Question 3 Comment
	achieved stakeholder consensus on the current language of the standard.
Response: The GVSDT thanks you for your comment.	
American Electric Power	The SDT should consider either removing MOD-026-1 R5 or merge R3 and R5 because a) MOD-026-1 R3 and R5 appear to have the same objective with similar wording and b) MOD-027-1 does not have the equivalent of MOD-026-1 R5.MOD-026-1 R6 ends with "...that includes the following:" yet whatever the SDT intended to follow is missing. Please note that subparts 1 through 3 are referenced in parenthetical statements within the respective requirements and that it does not make sense that these subpart criteria are also what needs to follow "...that includes the following:"
Response: The GVSDT thanks you for your comment. The peer review type activities in R3 are for units which have been verified per the standard, or the verification process is on-going, but there are potential issues regarding the model. The associated Requirement R5 does allow the TP a means to pursue model information from additional units if the model's predicted response does not match the actual equipment response for units that are above the threshold in the current NERC Registry Criteria but below the standard's base Applicability MVA thresholds. The SDT believes this is a reasonable way to allow the TP to pursue model information in the rare instances where there is an issue with a model that is not part of the base applicability. Additionally, the SDT has clarified Section 4.2.4 in the Applicability Section as follows: "A technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner." A requirement equivalent to MOD-026 R5 is not being proposed for MOD-027-1. It is extremely unlikely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit. Also, governor response is not consistent from one frequency excursion event to the next. Therefore, the SDT did not feel that such a Requirement in MOD-027-1 was necessary. Regarding the comment for Requirement 6, the SDT agreed that the sentence needed clarification. As such, the SDT decided to break the sentence up, with the first sentence ending at the next to last use of the word "usable." The second sentence now reads: The TP will provide a technical description of why the model is not usable. The SDT believes this will clarify the confusion that you pointed out.	
PPL Corporation NERC Registered Affiliates	The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system

Organization	Question 3 Comment
	Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. **Response: Excitation control system model is well established and documented. Some of those documents are referenced in Section G of the standard, including IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. The acceptable models referenced in Requirement 1 will predominately consist of standard library**

Organization	Question 3 Comment
	models included in software manufacturer dynamic simulation packages and are well known and understood – many are models developed by IEEE. Information on the transmission system beyond the point of interconnection is not required. EPRI has developed software which supports non invasive ambient monitoring for model verification that is successfully being used by a number of entities. Other developers have also developed similar software. While it is true that many generators do not currently have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. This standard has already undergone a NERC field test in the Summer of 2007 – one of the conclusions was that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. Entities from four regions participated, and all successfully completed the field test which validated that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed “usable” by the TP. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Also the SDT consciously avoided specifying the quality of match between model and test a) to avoid risk of being over-prescriptive and too restrictive and b) because an industry accepted quantification of “match” does not exist. The focus is solely on “what” is required, not “how” it’s**

Organization	Question 3 Comment
	done. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip overspeed excursion. **Response: The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. **The SDT believes that we have achieved stakeholder consensus on the current language of the standard. The SDT believes specifying reportable thresholds for an infinite number of possible permutations is not practical for a standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Southwest Power Pool Reliability Standards Development Team	There is a problem with the threshold in the standard of 100MVA units. We would suggest that this be in line with the BES DEF and reduce this threshold to 20MVA. Why has the threshold been increased? If the data has to be provided for LGIA under the Tariff then we should be verifying the data. There is also inconsistency between the standards posted for comment I.E. PRC-019-1. We would like to see better consistency for the thresholds between all the standards under this project and with the other projects associated with generator thresholds.
Response: The GVSDT thanks you for your comment. The individual unit and aggregate plant ratings used in the applicability section were carefully derived for each Interconnection to capture validation of approximately 80% of the total installed base in that region. The selection of these applicability requirements intend to strike the most reasonable balance between managing the	

Organization	Question 3 Comment
costs to perform tests and validation vs. ultimately assuring that the reliability of the Bulk System is not compromised due to poor models. It is recognized that boundaries within an interconnection can be drawn that can result in more or less than 80% of the connected MVA. However, R5 allows the TP to request the GO to perform a model review, if the unit is not included in the base Applicability but if that unit which is equal to or greater than the thresholds in the NERC Registry Criteria. **Regarding your comment asking for better consistency for the thresholds between all the standards under the GV SDT effort, each individual standard was developed based on the reliability needs and benefits that each specific standard requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor will the applicable facilities necessarily be the same.**	
Duke Energy	Typo - In the Effective Date section 5.3, strike the word “thirty” after the word “quarter” in the fourth line in the clean version.
Response: The GVSDT thanks you for your comment. The extra “thirty” has been removed in the current draft of the standard.	
Utility Services	Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comment. The percentages in the Effective Date section refer to the entity’s applicable unit gross MVA for each Interconnection. The SDT believes this is a clear designation that the thresholds are determined by the percent of unit gross MVA and not by the number of units. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.	
NIPSCO	Verification requirements would be burdensome, e.g., model response by staged testing or

Organization	Question 3 Comment
	comparison with a system disturbance may be of only limited value. Another basic problem with this standard is the unnecessary back and forth between generation owners and transmission planners in the data development and collection. This standard could be greatly simplified for all involved parties with reporting requirements similar to MOD-025 where the generation owner provides information to the transmission planner upon the installation of new equipment or the modification of existing equipment. Given the above, Transmission Planning recommends a vote against this standard in its present form.
Response: The GVSDT thanks you for your comment. The SDT believes peer review is an essential part of the model verification process irrespective of criteria or guidelines available from industry since peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. This peer review process is not necessary for the validation of unit steady state parameters, but is necessary for dynamic model verification to ensure accurate models that are compatible with dynamic simulation programs. Also, the SDT believes that the recording of the unit's response to a staged open or closed step in voltage test and/or an ambient voltage event is of great value and can be used to verify the model. Note that utilizing ambient monitoring inherently removes the need for any staged testing.	
ReliabilityFirst	VSL Requirement R6 - ReliabilityFirst still believes the VSL for Requirement R6 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R6 clearly requires the Transmission Planners to "...notify the Generator Owner... ", while the corresponding VSL states "The Transmission Planner provided a written response to the Generator Owner indicating..." The VSL is adding additional requirements on the TP (i.e. provide written response) which are not required within the actual requirement (nowhere in R6 is the TP required to provide a written response). If it is the intent of the SDT to have the TP provide a written response, ReliabilityFirst recommends adding that language to the requirement.
Response: The GVSDT thanks you for your comment. The GVSDT has made the requested edit in R6 indicating that the response by the Transmission Planner to the Generator Owner is required to be a written response.	

Organization	Question 3 Comment
PSEG	We voted “Negative” on this standard the reasons shown below.This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1.1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a “team” with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as “applicable facilities,” while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments:”The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.”The SDT responded as follows:”The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.”In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses:MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.”PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.”We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon.This **Response: The GVSDT is indeed working as a “team” with these standards. Each individual standard was developed based on the reliability needs and benefits that each specific standard requires. There are fundamental differences in the types of verifications required under each standard. Therefore, the reliability needs for each standard will not necessarily be the same, nor**

Organization	Question 3 Comment
	will the applicable facilities necessarily be the same. Given the response by industry in a prior posting, the GVSDT concludes that stakeholder consensus has been achieved with respect to not including synchronous condensers in the current draft of MOD-026, given the qualifications that follow: **Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that with the current structure of the Compliance Registry Criteria, if there is a need to develop a Reliability Standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.** SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1.2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1, R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all "modelers," the result will be outdated data in someone's model, which can have a bad result. The team should have one broad "data sharing" policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of

Organization	Question 3 Comment
	receiving a request for **Response: The GVSDT has written the requirements of this body of standards based on the NERC Reliability Functional Model. The requirements of Reliability Standards MOD-010-0. MOD-011-0, MOD-012-0 and MOD-013-1 address the requirement for steady state and dynamic models (which are planning models) and the dissemination of these models to appropriate entities. The data to build Real-time models that are necessary for reliability and used by Reliability Coordinators and Transmission Operators are addressed in standards IRO-010-1a and TOP-003-2 respectively. The GVSDT does not see any reason to include duplicative requirements in this standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
ISO-New England	Requirement R1 may bring out some concern over the copyrighted models supplied by the simulation software vendors. Hopefully this can be worked out with the vendors. **Response: The software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets.** Requirement R2.1.3 should indicate the requirement for the total combined *turbine*/generator inertia constant. Simulations need to study the combined inertia of the turbine and generator not just the generator. **Response: The SDT believes that the term used in the draft standard, total rotational inertia, clearly conveys that it is the entire inertia that is connected to the shaft driving both the turbine and the generator and any other mass.** A requirement R2.1.7 should be added to require verification of generator excitation limiter settings. **Response: The SDT believes that the specificity in Part 2.1.3 includes any model data that is relevant to the verification of the excitation control system.** A requirement R2.1.8 should be added to require verification of supplementary voltage control inputs. **Response: The SDT believes that the specificity in Part 2.1.3 includes any model data that is**

Organization	Question 3 Comment
	relevant to the verification of the excitation control system Requirement R3 only requires a "written response" from a Generator Owner to the Transmission Planners notification that a model is not useable. Wording must be included so that ultimately the Generator Owner shall provide a "usable model" to the Transmission Planner. **Response: Requirement R3 is a "peer review" type requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to request the Generator Owner to review the data and assist in identifying problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process was over whelming supported by Industry based on their responses in prior postings.** Requirement R4 must be modified so that models are provided prior to making changes in the excitation control system or plant volt/var control function. It is counter to system reliability to allow generators to modify and subsequently operate equipment without notifying the Transmission Planner. **Response: This standard addresses model verification, not the submittal of preliminary design models. Model verification can occur only after the equipment changes are implemented. The standard does not address development of the original model during the equipment commissioning process. The SDT believes that we have achieved stakeholder consensus on the current language of the standard.** Footnote 6 should be modified to include ability for the Transmission Planner to require a verified model from a generator under the size threshold if the generator impacts the BES. **Response: Regarding provision of a reason the unit impacts the BES, R5 and Footnote 6 have undergone several modifications around this point. The SDT believes the existing R5 and Footnote 6 language strikes the best compromise to equitably satisfy all stakeholders as it allows Transmission Planners a way to request revised model data or a model verification for models that meet or exceed the NERC registry criteria thresholds but is below the standard's base applicability.**

Organization	Question 3 Comment
	Requirement R6 sub-requirement wording should be changed to indicate the Transmission Planner shall notify the Generator Owner if the excitation model *does not* initialize, a no-disturbance simulation results in transients or a disturbance simulation results in a model exhibiting negative damping. **Response: The SDT has modified the language in R6 and we believe that the new language will address your concerns.**
Response: The GVSDT thanks you for your comment. Please see responses above.	

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2007-09 Generator Verification
PRC-024-1

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to PRC-024-1. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 54 sets of comments, including comments from approximately 149 different people from approximately 78 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Summary Consideration

During the last posting period, the GVSDT had revised the VRFs for Requirements R1, R2 and the original R5 to “medium” and asked stakeholders if they agreed with the proposed VRFs. The GVSDT did not receive any comments on this revision and all stakeholders agreed with the revised VRFs.

The GVSDT revised R4 to improve clarity. A majority of the stakeholders agreed that the revision had improved clarity. Some stakeholders were still unclear if the activities described in this requirement were to be performed by request only, so the SDT rearranged the sentences to make that more clear. Some stakeholders pointed out the RCs and TOPs can request such information via requirements in other standards (IRO-010-1a and TOP-003-2), so these two functional entities were removed from this requirement.

Based on comments from a majority of stakeholders, Requirement R5 (along with its associated Measure M5 and VSL’s) was removed from the Standard. The SDT believes that Requirement R4 achieves the reliability objective of Paragraph 1787 of FERC Order 693 that Requirement R5 was written to address. Other changes were made in response to comments from several stakeholders including:

- Additional wording in the Effective Date section for jurisdictions where regulatory approval is required to address the situation in some Canadian provinces.
- A modification to the high frequency allowable trip point in Attachment 1 for the Eastern and ERCOT Interconnections to match IEEE and IEC standards for generator manufacturers.
- A modification to the final voltage value of the low voltage curve and time duration of Attachment 2 to coordinate with the requirements of PRC-025 Generator Relay Loadability.
- Rearrangement of the sentences in Requirement R4 to better clarify that developing the estimate of performance is to be done only on request of certain planning entities.
- Removal of the Reliability Coordinator and Transmission Operator from the list of functional entities who can request a performance estimate in Requirement R4 and protection settings information in Requirement R6 to eliminate duplication with standards IRO-010 and TOP-003.
- Various wording changes made to improve consistent use of terminology and to improve readability.

Several stakeholders pointed out that a portion of the allowable high frequency trip curve for the Eastern, ERCOT, and Quebec Interconnections (Attachment 1) exceeded the off-nominal frequency limits in IEEE C50.13 and IEC 60034 that are used by equipment manufacturers to design generators.

The drafting team revised the high frequency portion of the curve from zero to two seconds for the Eastern and ERCOT Interconnections to meet the IEEE and IEC standards. This leaves no margin between the high frequency allowance for UFLS designers in frequency overshoot for that amount of time, but the drafting team feels this is acceptable.

Index to Questions, Comments, and Responses

1. The GVSDT revised the VRFs for Requirements R1, R2 and R5 to “medium”. Do you agree with this revision? If not, please explain in the comment area below. 13
2. The GVSDT revised R4 to improve clarity. Do you agree with this revision? If not, please explain in the comment area below. 16
3. Do you have any other comment, not expressed in questions above, for the GVSDT? 28

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool		NA
2.	John Allen	City Utilities of Springfield		1, 4
3.	Katie Shea	Westar Energy		1, 3, 5, 6
4.	Sean Simpson	Board of public utilities of kansas city		1, 3, 5
5.	Mark Wurm	BPUK		NA
6.	Lynn Schroeder	Westar Energy		1, 3, 5, 6
7.	Don Taylor	Westar Energy		1, 3, 5, 6
8.	Brian Taggert	Westar Energy		1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

3.	Group	David Thorne	Pepco Holdings Inc	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light	RFC	1, 3

4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2. Chuck Matthews	Transmission Planning	WECC	1
3. Erika Doot	Generation Support	WECC	3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	ryan millard	pacificorp	X		X		X	X				

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	Dewayne Scott		SERC	1
5.	Tom Vandervort		SERC	5
6.	Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	George Pitts		SERC	1
9.	Robert Bottoms		SERC	1
10.	David Marler		SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Shammara Hasty	Southern Company	X		X		X	X				

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Steve Rueckert	Western Electricity Coordinating Council										

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Steve Kern	FE Energy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2. Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3. Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4. Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

11.	Group	paul haase	seattle city light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. pawel	krupa	WECC	1
2. dana	wheelock	WECC	3
3. hao	li	WECC	4
4. mike	haynes	WECC	5
5. dennis	sismaet	WECC	6

12.	Group	E Scott Miller	MEAG Power	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Steve Jackson	MEAG Power	SERC	3
2. Steve Grego	MEAG Power	SERC	5
3. Danny Dees	MEAG Power	SERC	1

13.	Group	Thomas McElhinney	JEA	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ted Hobson		FRCC	1
2. Garry Baker		FRCC	3
3. John Babik		FRCC	5

14.	Group	Brenda Hampton	Luminant						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Laney	Luminant Generation Company, LLC	ERCOT	5

15.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2. John Shaver	Southwest Transmission Cooperative	WECC	1
3. Tom Alban	Buckeye Power	RFC	3, 4
4. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	David Sofra	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4. Greg Cecil	Duke Energy	RFC	6										
19.	Group	Al DiCaprio Chair	ISO RTO Council Standards Review Committee		X								
Additional Member	Additional Organization	Region	Segment Selection										
1. Greg Campoli	NYISO	NPCC	2										
2. Ben Li	IESO	NPCC	2										
3. Bill Phillips	MISO	RFC	2										
4. Charles Yeung	SPP	SPP	2										
5. Matthew Goldberg	ISONE	NPCC	2										
6. Steve Myers	ERCOT	ERCOT	2										
7. Ali Miremadi	CAISO	WECC	2										
20.	Individual	Brian Bejcek	Wolverine Power Cooperative	X									
21.	Individual	Jim Watson	Dynegy					X					
22.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
23.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
24.	Individual	Carter B. Edge	SERC Reliability Corp										X
25.	Individual	Winnie Holden	PSEG	X		X		X	X				
26.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
27.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (voting under entity name Occidental Chemical Corporation)					X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
32.	Individual	Michael Falvo	Independent Electricity System Operator		X								
33.	Individual	Patrick Brown	Essential Power, LLC					X					
34.	Individual	Wryan Feil	Northeast Utilities	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Brian Evans-Mongeon	Utility Services								X		
36.	Individual	Mike Hirst	Cogentrix Energy					X					
37.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
38.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
39.	Individual	John Yale	Chelan County PUD					X					
40.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
41.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
42.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
43.	Individual	Eric Bakie	Idaho Power Company	X		X							
44.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
45.	Individual	Daniela Hammons	CenterPoint Energy	X									
46.	Individual	Kirit Shah	Ameren	X		X		X	X				
47.	Individual	Don Jones	Texas Reliability Entity										X
48.	Individual	Marie Knox	MISO		X								
49.	Individual	Mary Downey	City of Redding			X	X	X	X				
50.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
51.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
52.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
53.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
54.	Individual	Chifong Thomas	BrightSource Energy					X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Entity
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Indiana Municipal Power Agency	Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum (NAGF)for PRC-024.
Nebraska Public Power District	MRO NSRF [MidwestReliability Organization - NERC Standards Review Forum]
Liberty Electric Power LLC	NAGF
Chelan County PUD	North Amnerican Generator Forum
City of Redding	SMUD/BANC
MEAG Power	Southern Comnpany Services, Inc. - GenMEAG Power intended to vote NEGATIVE on this ballot. The Affirmative vote is an error. If the draft standard is not changed based upon the comments, MEAG Power will vote Negative on the Recirulation ballot.
MISO	The ISO/RTO Council's (IRC) Standards Review Committee (SRC)

1. The GVSDT revised the VRFs for Requirements R1, R2 and R5 to "medium". Do you agree with this revision? If not, please explain in the comment area below.

Summary Consideration: All stakeholders agreed with the revised VRFs.

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revised VRFs for R1, R2 and R5.
Response: The SDT thanks you for your comment.		
Manitoba Hydro	Yes	None.
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc	Yes	
Bonneville Power Administration	Yes	
pacificorp	Yes	
Southern Company	Yes	
FirstEnergy	Yes	
Luminant	Yes	
ACES Power Marketing Standards	Yes	

Organization	Yes or No	Question 1 Comment
Collaborators		
PPL Corporation NERC Registered Affiliates	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Duke Energy	Yes	
Wolverine Power Cooperative	Yes	
Dynegy	Yes	
TransAlta Centralia Generation LLC	Yes	
SERC Reliability Corp	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (voting under entity name Occidental Chemical Corporation)	Yes	
American Transmission Company	Yes	
Wisconsin Electric Power Company	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 1 Comment
Operator		
Northeast Utilities	Yes	
Omaha Public Power District	Yes	
South Carolina Electric and Gas	Yes	
Exelon Corporation and its affiliates	Yes	
Ameren	Yes	
Texas Reliability Entity	Yes	
BrightSource Energy	Yes	

2. The GVSDT revised R4 to improve clarity. Do you agree with this revision? If not, please explain in the comment area below.

Summary Consideration: A majority of the stakeholders agreed that the revision had improved clarity. Some stakeholders were still unclear if the activities described in this requirement were to be performed by request only, so the SDT rearranged the sentences to make that more clear. Some stakeholders pointed out the RCs and TOPs can request such information via requirements in other standards, so these two functional entities were removed from this requirement.

Organization	Yes or No	Question 2 Comment
Tennessee Valley Authority	No	Recommend that the R4 be enhanced to give more detail on how to satisfy this requirement. As significant as R4 is, the Generator Owners need more guidance than what is currently stated.
Response: The SDT thanks you for your comment. The SDT does not believe the requirements should be prescriptive as to how to accomplish the reliability goals. We agree some level of technical guidance can be developed, but that it should not be in the standard.		
seattle city light	No	Seattle City Light votes NO because it is unclear the type of data the Reliability Coordinator, Planning Coordinator, Transmission Planner, and/or Transmission Operator is to provide the Generator Operator. Until Reliability Coordinators, Transmission Planners, Planning Coordinators, and/or Transmission Operators agree to and approve acceptable simulations and dynamic models, it is difficult for Seattle City Light to approve this standard. There are requirements included in R4 and R5 that have not been communicated with Generator Operators in the past, and without agreement about simulations and models, it is simply too unclear.
Response: The SDT thanks you for your comment. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who		

Organization	Yes or No	Question 2 Comment
indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. As noted, the SDT feels Requirement R4 must remain in the standard in order to satisfy the requirements of the SAR to meet the directives of FERC Order 693 – in this case Paragraph 1787 of the Order.		
Luminant	No	Because R4 is only requiring an estimate of a unit's ability to ride through an excursion developed by a planner, the generator owner should only state if the unit is or is not capable of staying on-line. R4 should be written to follow the FERC order. It is recommended that R4 be written as such. R4) Each Generator Owner of a generating unit shall respond within 60 days of receipt of a written request by the requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner that monitors or models the associated generating unit) stating if generating unit(s) or plant is or is not expected to ride through a frequency or voltage excursion based on a dynamic simulation provided by the requestor.
Response: The SDT thanks you for your comment. The SDT believes there is merit in the estimate of the amount of time following an event that the unit would remain connected and has elected to leave the wording as is.		
ACES Power Marketing Standards Collaborators	No	(1) We question the value of this requirement and suggest it should be struck. While knowing how long a generator will remain connected following a voltage or frequency excursion might be useful to a planning engineer conducting dynamic simulations, we do not see how it helps the RC, BA or TOP. The RC, BA or TOP's System Operator will not likely take any action as a result of such information. Rather, they will wait to see if the unit trips before taking additional action because

Organization	Yes or No	Question 2 Comment
		there is no guarantee the unit will trip. Then, they will already be taking actions to minimize the stress regardless of whether they suspect that a unit may trip due to a voltage or frequency excursion. System Operators always have to be prepared to respond to events but simply cannot be expected to respond to every possible event because most simply don't happen and it would be an unreasonable expectation of System Operator. Even if the System Operator knew that a unit might trip in a short time frame due to a voltage or frequency excursion, they simply do not know when such an excursion might or even will occur and likely would not take preemptive action. Because System Operators are responsible for monitoring many aspects of the BES, it would be a waste of time to have them speculating whether or not a unit is going to trip. The system operator only needs to know how to react and mitigate the event if a unit does in fact trip. Furthermore, the RC, BA, and TOP already operate the system to withstand the loss of a unit so any unit that would trip due to such an excursion would not cause a problem. Upon the actual unit trip, then the RC, BA and TOP can reposition the system if necessary to prepare for the next contingency. When information is supplied to a System Operator that does not require them to do something it becomes "noise" which provides no value. **Please note that the BA function is not listed within this standard. The RC and TOP have been removed from this requirement per your comment below to eliminate redundancy with the other standards you cited. As you note in this comment, the time duration between initiation of an event and a unit trip is of value to a PC or TP doing stability studies and has been retained in Requirement R4.** (2) IRO-010-1a and TOP-003-2 already allow the RC and TOP to request necessary data from the Generator Owner through their data specification and have the authority to compel the Generator Owner to provide the data. Thus, if this data is needed the RC and TOP will include it in their data specifications. As a result, supplying the portion of R4 that requires data to be supplied to the RC and TOP is redundant and unnecessary. **The SDT agrees with your comment and has removed the RC and TOP from Requirement R4. As you note, these entities still may obtain the information via the requirements in the other cited standards.**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>(3) What level of voltage or frequency excursion is intended to be covered by this requirement? It does not appear to be specified. The requirement specifies that the requesting entity is to provide the Generator Owner with the voltage or frequency excursion profile to be evaluated.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment. See responses to your specific comments above.</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>The Protective Relay coordination portions of this standard are not being contested. It is not clear how the evaluations should be performed to determine the ability to ride through grid transients. A standard should NOT be written to require this until research has been done to document an appropriate approach to doing these evaluations. It is suggested that plant performance requirements be removed from this Protection System (PRC) standard. If this is required to support grid reliability, then a new SAR should be written to develop those plant performance requirements.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. As noted, the SDT feels Requirement R4 must remain in the standard in order to satisfy the requirements of the SAR to meet the directives of FERC Order 693 – in this case Paragraph 1787 of the Order.</td></tr>
<tr><td>Associated Electric Cooperative, Inc. - JRO00088</td><td>No</td><td>As currently drafted, Requirement R4 appears to dictate an analysis for all inflection-points in unit performance, for a continuum of frequency and voltage excursions, and</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		taking into account all of the underlying auxiliary equipment's control systems and settings. We see this current draft's Requirement R4 wording as a creating a much greater expectation, than estimating the duration-times for the curves at the specific inflection-points given in Attachments 1 & 2 of this Standard.
Response: The SDT thanks you for your comment. The requirement specifies that the requesting entity is to provide the Generator Owner with the voltage or frequency excursion profile to be evaluated. The Generator Owner is not expected to arbitrarily evaluate all possible voltage and frequency excursion profiles.		
Duke Energy	No	1) It is unclear if this requirement is to be only upon request, and if requests will be related to the same ride through criteria or a different set specified by the TP. Need to clarify how this aspect will be executed. **The wording of the Requirement has been rearranged to help clarify that the estimate is to be provided only upon request.** 2) Refer to discussion in our response to Question 3 below about industry concerns with the technical viability of plant performance standards.
Response: The SDT thanks you for your comment. See responses to your specific comments above and at Question 3.		
ISO RTO Council Standards Review Committee	No	The proposed language lacks clarity in what data is needed in order for a TOP to comply with the requirement to provide trip settings to the RRO/RC/Transmssion Planners. We recommend that regions develop further specific "no-trip" regions specific to their area of the Interconnection.
Response: The SDT thanks you for your comment. There is no language in Requirement R4 for the TOP to provide any information to the RRO, RC, or Transmission Planner. If the TOP requests a Generator Owner to evaluate the ride-through performance of a particular generating facility, then that TOP must provide the GO with the specific transmission system voltage excursion profile or frequency excursion profile to be evaluated as stated in this requirement.		
Dynegy	No	R4 requires the GO to provide the Transmission Planner an estimate of the time duration a generator will stay on during a frequency or voltage excursion. It appears

Organization	Yes or No	Question 2 Comment
		this question would already be answered in complying with R2 when the GO verifies the relay settings against the graphs in Attachment 2. It's also not clear whether R4 is to be accomplished before or after a request from the Transmission Planner. It is recommended R4 be removed. If it is not removed, add "...if requested." at the end of the first sentence.
Response: The SDT thanks you for your comment. The requesting entity (Transmission Planner or Planning Coordinator) might be aware of the trip set points for the Generator Protection System as specified in Requirements R1 and R2, but Requirement R4 specifically states that the Generator Owner must consider the performance of the auxiliary systems when providing the estimate to the requesting planner. The expectation is that the protection will not operate during an excursion but the plant may still trip due to process upsets caused by auxiliary systems reaction to the excursion. The wording in Requirement R4 has been rearranged to clarify that the estimate is to be provided only upon request.		
Ingleside Cogeneration LP (voting under entity name Occidental Chemical Corporation)	No	Unlike MOD-026-1, which requires some amount of justification from the requesting entity before action must be taken, PRC-024-1 R4 requires compliance without any regard to the Generator Owner's resource availability. In general, Ingleside Cogeneration LP believes that a good working relationship between the Generator Owner and Transmission Planner includes a reasonable justification for any request that requires time and expense on the part of the other.
Response: The SDT thanks you for your comment. The Generator Owner must perform the verification activities described in MOD-026-1 on a 10-year basis, absent any justification from any entity. The SDT congratulates Ingleside for maintaining a good relationship with your Transmission Planner. The Transmission Planners on the SDT indicate that a request for an estimate would likely only be for facilities that appear to be critical to stability immediately following an excursion.		
American Electric Power	No	R4 should be removed entirely from this standard. R4 appears to add no reliability benefit beyond what is already prescribed in R3. Documentation of equipment limitations as possible causes for tripping within the no-trip zones of Attachments 1 and 2 will allow PCs and other entities to check for instances where UFLS effectiveness or system voltage recovery might be compromised by possible early tripping of generators due to factors other than relay settings. As these benefits

Organization	Yes or No	Question 2 Comment
		seem to be the intent of R3, R4 does not appear to add any useful information beyond what would already be supplied under R3. We further expect that GOs will be unable to devise the required estimates of time duration without detailed simulations of generating unit and auxiliary system performance (the explicit statement that detailed studies are not required notwithstanding) during the specified frequency or voltage excursion profiles to be supplied to them. Were these intended to be trajectories rather than profiles?
Response: The SDT thanks you for your comment. The SDT feels Requirement R4 is needed to comply with the SAR for this project that mandates the SDT consider directives in FERC Order 693 – in this case Paragraph 1787. The intent of Requirement R3 is to allow owners of generating facilities to set protection to operate inside the "No Trip Zone" of Attachments 1 or 2 if there is a known limitation that prevents operation in a portion of the "Zone" (e.g., a manufacturer's bulletin describing a limitation on operating below certain frequencies). The Generator Owner must communicate these settings that fall inside the "No Trip Zone" to the appropriate entities that model the facility for stability contingencies. This does not mean the entities modeling the facility are aware of how the facility might react when the performance of the auxiliary systems are considered, which is the intent of Requirement R4. No change made to the requirement.		
Wisconsin Electric Power Company	No	We maintain that there is no reliability driven need for R4. Also, such estimates would be of limited accuracy. Should such an estimate be deemed useful, it can be requested informally among the appropriate entities. Standards and associated requirements must be reserved for those items more critical to BES reliability
Response: The SDT thanks you for your comment. The SDT feels Requirement R4 is needed to comply with the SAR for this project that mandates the SDT consider directives in FERC Order 693 – in this case Paragraph 1787. Accurately modeling the performance of generating facilities can impact stability assessments. No change made to the requirement.		
Exelon Corporation and its affiliates	No	In response to Exelon's (and other commenter's) concern that 60 calendar days was not a reasonable amount of time to perform a study in response to a written request from a RC, PC, TOP or TP, the GVSDT stated that it has "modified the structure of the requirement to clarify the intent and the limits of what entities could request a performance estimate;" but the GVSDT was not in agreement with changing the time

Organization	Yes or No	Question 2 Comment
		period allowed to respond. Although the GVSDT states that "[d]etailed unit performance studies are not required to develop the estimate," Exelon continues to maintain that 60 calendar days is not a reasonable amount of time to perform a study of this magnitude based on the predicted scope. Specifically, nuclear generating units have extensive calculations related to how internal systems will respond to frequency and voltage excursions. Exelon believes it is inappropriate to short cycle or challenge the rigorous process required by the Nuclear Regulatory Commission (NRC) at a nuclear generating unit for any such study. In addition, depending on the complexity of the transient requested by the transmission entity, a nuclear generating unit may not have the in-house expertise to perform such a study and may be required to hire an outside vendor.
Response: The SDT thanks you for your comment. The SDT has made it clear in responses to similar comments during previous postings that the SDT does not believe extensive studies or dynamic simulations are required to comply with this requirement. Such studies would achieve only a very minimal increase in the reliability of the estimate given the number of variables involved.		
CenterPoint Energy	No	(a) To improve clarity, CenterPoint Energy recommends deleting the second and third sentences of the first paragraph of R4. CenterPoint Energy does not agree that a Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner should provide a voltage or frequency profile at the point of interconnection that is determined by dynamic simulation. Different types of simulated events will produce different voltage and frequency excursions. Also, even the same type of event will produce different voltage and frequency excursion "profiles" as the system changes over time. **The SDT feels that if the Generator Owner is not provided an excursion profile, the GO would not know what profile to evaluate. The curves in Attachments 1 and 2 are frequency and voltage magnitude vs. allowable time duration envelopes that encompass the set of possible profiles that could occur. They are not actual excursion profiles.** (b) While deleting the second and third sentences of the first paragraph of R4 would provide clarity, it would nevertheless be problematic for reliability because it does

Organization	Yes or No	Question 2 Comment
		not impose any minimum frequency or voltage ride-through requirements for existing generation stations. Failure of a generator to ride-through at least some minimum threshold of frequency and voltage excursions places the reliability burden solely on transmission entities and makes is difficult to compensate for the generator's failure to perform. **The SDT believes that existing generating facilities have a good track record of riding through voltage and frequency excursions. Cascading outages caused by trips of multiple generating facilities due to a single event are extremely rare. The SDT does not believe the recommended requirement is necessary.**
Response: The SDT thanks you for your comment. See responses to your specific comments above.		
SMUD	No	We agree that a GO can meet the requirements in R1 & R2 and use R3 to note any known limitations. We do not feel the GO can provide any meaningful estimate of overall plant performance beyond meeting the first three requirements. The complexity of what is being asked is simply too great.
Response: The SDT thanks you for your comment. The SDT believes a reasonable estimate can be achieved by determining what auxiliary equipment would cause a turbine or generator trip if that equipment were to shut down due to an excursion. Fans, pumps, compressors, etc., that could cause process upsets if they shut down due to contactor dropout during low voltage or slow down due to frequency decay could be looked at and a worst case estimate developed. The SDT realizes that this type of evaluation may not reflect what happens in actuality, but it will probably be conservative (from the planner's perspective). Performing extensive (and expensive) dynamic simulations would bring only marginal improvement in the accuracy of the estimate given the large number of variables involved.		
Cowlitz PUD	No	Requirement R4 is clear, however it can take 60 calendar days simply to find and retain a consulting firm who is qualified to provide the estimated data to the requesting entity. This will require the GO to perform defensive compliance, that is, to attempt to aquire data before a request is submitted in order to meet the tight two-month response time. There is no provision to allow the GO to negociate a time frame with the requesting entity.

Organization	Yes or No	Question 2 Comment
Response: The SDT thanks you for your comment. The SDT believes the plant staff should be able to provide a reasonable estimate that satisfies Requirement R4. If they identify which auxiliary equipment (pumps, fans, etc.) would cause a generator trip if that equipment drops out due to voltage excursion, then identify the one that would cause the trip the fastest (e.g., would a boiler pressure excursion due to loss of a fan cause a trip faster than a boiler drum level excursion due to loss of a pump). If Cowlitz still feels the need to contract a consultant, perhaps the contract could be negotiated ahead of time.		
Dominion	Yes	R4.1. and R4.2. are listed in the redline standard, but not in the clean version of the standard.
Response: The SDT thanks you for your comment. The SDT is aware that the redline version does have issues. Please refer to the clean version for the most accurate information.		
Manitoba Hydro	Yes	Manitoba Hydro noticed that the “clean” and “redline” versions of the standard are inconsistent. Both 4.1. and 4.2. should be removed from the “redline” version since both are redundant (included in the text of R4.).
Response: The SDT thanks you for your comment. The SDT is aware that the redline version does have issues. Please refer to the clean version for the most accurate information.		
Idaho Power Company	Yes	Idaho Power System Planning agrees with the revisions made to R4.
Response: The SDT thanks you for your comment.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
pacificorp	Yes	
Southern Company	Yes	
FirstEnergy	Yes	
Wolverine Power Cooperative	Yes	
TransAlta Centralia Generation LLC	Yes	
SERC Reliability Corp	Yes	
PSEG	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Omaha Public Power District	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	

Organization	Yes or No	Question 2 Comment
Texas Reliability Entity	Yes	
BrightSource Energy	Yes	
Western Electricity Coordinating Council		Should part 4.2 read Identification of the basis rather than Identification of the bases
Response: The SDT thanks you for your comment. The word “bases” is the plural of “basis”.		

3. Do you have any other comment, not expressed in questions above, for the GVSDT?

Summary Consideration: Based on comments from a majority of stakeholders, Requirement R5 (along with its associated Measure M5 and VSL's) was removed from the Standard. The SDT believes that Requirement R4 achieves the reliability objective of Paragraph 1787 of FERC Order 693 that Requirement R5 was written to address. Other changes were made in response to comments from several stakeholders including:

- **Additional wording in the Effective Date section for jurisdictions where regulatory approval is required to address the situation in some Canadian provinces.**
- **A modification to the high frequency allowable trip point in Attachment 1 for the Eastern and ERCOT Interconnections to match IEEE and IEC standards for generator manufacturers.**
- **A modification to the final voltage value of the low voltage curve and time duration of Attachment 2 to coordinate with the requirements of PRC-025 Generator Relay Loadability.**
- **Rearrangement of the sentences in Requirement R4 to better clarify that developing the estimate of performance is to be done only on request of certain planning entities.**
- **Removal of the Reliability Coordinator and Transmission Operator from the list of functional entities who can request a performance estimate in Requirement R4 and protection settings information in Requirement R6 (now R5) to eliminate duplication with standards IRO-010 and TOP-003.**
- **Various wording changes made to improve consistent use of terminology and to improve readability.**

Several stakeholders pointed out that a portion of the allowable high frequency trip curve for the Eastern, ERCOT, and Quebec Interconnections (Attachment 1) exceeded the off-nominal frequency limits in IEEE C50.13 and IEC 60034 that are used by equipment manufacturers to design generators. The drafting team revised the high frequency portion of the curve from zero to two seconds for the Eastern and ERCOT Interconnections to meet the IEEE and IEC standards. This leaves no margin between the high frequency allowance for UFLS designers in frequency overshoot for that amount of time, but the drafting team feels this is acceptable.

Organization	Yes or No	Question 3 Comment
ACES Power Marketing		(1) We appreciate that the second bullet allows that TP to provide a less stringent voltage envelope for R5. However, it is not clear if the TP can provide a more

Organization	Yes or No	Question 3 Comment
Standards Collaborators		stringent envelope. We believe a more stringent voltage envelope should not be allowed. Please clarify. **While Standard PRC-024 (R2 and R5) allows the TP to provide a less stringent voltage envelope, the TP cannot enforce a more stringent voltage envelope.** (2) We continue to believe that requirement R5 needs to be modified to recognize that equipment will not always be new and may develop limitations as it ages. These limitations may prevent the generator from meeting the voltage and frequency envelopes defined in Attachment 1 and 2. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** (3) Requirement R6 should be struck. First, the TOP and RC already have the capability to request such data in its data specification from the GO through IRO-010-1a and TOP-003-2 which also compels the GO to comply with the data specification. Thus, if the TO and GO need the data they will write it into their data specifications. Second, this requirement is the type of requirement that the Project 2013-02

Organization	Yes or No	Question 3 Comment
		Paragraph 81 drafting team has proposed eliminating in response to the FERC approval order of the FFT process. Specifically, the requirement meets the Administrative, Purely Reporting and Redundant criteria for the project. It only has to meet one criterion to be proposed for retirement. It is imperative that drafting teams refrain from developing requirements that a future team will retire. **Based on comments from you and numerous stakeholders the SDT has decided to modify the wording for requirement R4 and (previous) R6 to include data requests from Planning Coordinators or Transmission Planners not Transmission Operators or Reliability Coordinators.** (4) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls, entity impact evaluation, elimination of zero-defect expectations). The VSL for Requirement R5 makes it clear that every time a "new unit" (i.e. does not meet footnote 2) trips, an evaluation needs to be conducted to determine if the unit tripped for a voltage or frequency excursion that is inside the no trip zone. To refocus NERC efforts on compliance, the recent compliance enforcement initiatives would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. These approaches are being written into the standards (CIP, COM-003, etc.). We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this requirement. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation**

Organization	Yes or No	Question 3 Comment
		facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. (5) Because the voltage envelope is based on assumptions listed on page 20, the VSLs for R5 need to clarify that if a unit does trip in the no trip zone and the system does not reflect these assumptions that this does not represent a violation. For instance, if a synchronous condenser or capacitor (bullet 7 on page 20) is not available that was assumed to be available when evaluating protection relay settings, why would the GO be held accountable for its unit tripping during a voltage excursion? It followed the assumptions set out in the standard. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the intent of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without**

Organization	Yes or No	Question 3 Comment
		the need for a requirement in a reliability standard. (6) Why is the defined term Protection System not used throughout the standard rather than "protective relaying"? We recommend adopting the NERC Glossary Term for consistency. **The SDT used the phrase protective relaying within the standard rather than Protective System, because Protective System is a broad definition in which communications, dc power supplies, and includes protective relays. Protective relaying is more applicable to this specific standard.** (7) We continue to believe that performance requirements for new units should be part of the interconnection process. As a result, R5 should either be struck or it should be moved to FAC-001 which governs standards for facility connection requirements. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.**

Organization	Yes or No	Question 3 Comment
		(8) Requirement R3 and R6 are the types of requirements the Project 2013-02 Paragraph 81 drafting team is proposing to eliminate. They have established a set of criteria to identify requirements with little to minimal reliability impact. Both of these requirements meet one or more of the following criteria: Administrative, Purely Documentation, Purely Reporting, or Little, if any, value as a reliability requirement. Please review all proposed requirements against this criteria and remove requirements as appropriate. While we believe R3 should be removed, we do understand there is a need to document equipment limitations for R1 and R2. We believe the existing associated bullets in R1 and R2 will satisfactorily address the need to document limitations and that the reference to R3 could simply be struck. **The SDT has reviewed the criteria for removing requirements per Paragraph 81 and determined that the requirements of PRC-024 do not meet the applicable criteria. In order to be considered for removal, a requirement has to meet Item A as well as at least one part of Item B (see P81 team criteria document). The requirements of PRC-024 do not meet Item A and therefore are not eligible for inclusion.** (9) Please remove the RC and TOP from Part 3.1 of R3. Inclusion of the RC and TOP is redundant with IRO-010-1a and TOP-003-2 which require the RC and TOP to develop data specifications. If they need this data, it should be included in their data specification. **The reference of the Reliability Coordinator and Transmission Operator is applicable for Part 3.1 of R3 as this sub requirement is applicable for the Generator Owner to communicate the documented equipment limitation, or the removal of a previously documented equipment limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner. No other standard or subsection of this standard covers this requirement.** (10) Please remove “as specified by Requirement R6” in the first half of the R6 VSLs. We found it confusing when it was not included in the second half. **For clarity, applicable changes will be made to the VSLs for R6 (now R5).**

Organization	Yes or No	Question 3 Comment
		(11) Please copy footnote 1 from R1 on to the page with R2. It was not immediately clear that he footnote in R2 was actually on the previous page. **The document has been modified to include footnote 1 on the same page as R1 and R2.**
Response: Thank you for your comments. Please see responses to specific comments above.		
Ameren		We commend the GVSDT for considering and addressing our previous comments, and making several changes that improve this proposed standard. (1)In R1 and R2, please add “Generation may trip by properly set volts per hertz protection if a system over excitation abnormality necessitates disconnecting a generating unit.” **The voltage ride-through time duration curve (Attachment 2) takes into account properly set volts per hertz relays, assuming that the frequency is 60 Hertz and adjustments are made to the magnitude of the high voltage curve in proportion to deviations of frequency below normal.** (2)Based on the GVSDT response to our previous comments we understand the purpose of R6 is to be studies. Given this study purpose, please change “and Transmission Planner” to “or Transmission Planner”, delete “monitors or” and replace “unless otherwise directed by the requesting Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner” with “while the requestor’s study is underway”. We believe that it is burdensome for the GO to have to indefinitely continue to send setting changes to the requesting entity. When the requesting entity begins another periodic study, they’ll request them again. Therefore, we request that R6 should then read: “Each Generator Owner shall provide its generator protection trip settings to the Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner (that models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings

Organization	Yes or No	Question 3 Comment
		while the requestor's study is underway." **Based on comments from you and other stakeholders the SDT has made applicable changes to each of the PRC-024 requirements.** (3)We believe that M5 expects the GO to retain evidence that proves the negative and is therefore burdensome. Generators trip for many reasons; most of them have to do with the mechanical system. We request that the SDT append "by the generator frequency or voltage protective relaying" after "each unit trip", and add "or that no such unit trips occurred within the Data Retention period" at the end. M5 should then read: "Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip by the generator frequency or voltage protective relaying did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied, or that no such unit trips occurred within the Data Retention period." **Since Requirement R5 has been removed from the standard, Measure M5 has been removed as well.** (4)VSL's in R3, R4, and R6 are set up with 10 day increments between the different severity levels, rather than a more typical 30 day increment. **The 10-day increments in R3, R4 and R6 (now R5) are based on VSL development guidelines provided by NERC. The SDT so feels that the 10-day increment is appropriate for this standard.** (5)As a general comment, NERC should make all the papers listed in the references section of the standard readily available on their website. **While this request would aid in understanding a given standard, copyright restriction prevent NERC from satisfying this request.**

Response: Thank you for your comments. Please see responses to specific comments above.

Organization	Yes or No	Question 3 Comment
CenterPoint Energy		(a) In R2 and R5, CenterPoint Energy recommends that "external to the generating plant" be deleted in the phrase "...caused by an event on the transmission system external to the generating plant..." We believe this could cause confusion, as some could consider the transmission interconnection substation as part of the generating plant. Also, such wording is not needed, as both requirements include the following clarifying language: "Generation may trip if clearing a system fault necessitates disconnecting a generating unit." **While the phrase "external to the generating plant" may cause some confusion, the STD felt that this phrase clearly defines which transmission facilities would be subject to evaluation, in the event that transmission and generation facilities are intertwined.** (b) CenterPoint Energy cannot support this version of PRC-024 because it does not impose any minimum frequency or voltage ride-through requirements for existing generation stations. Failure of a generator to ride-through at least some minimum threshold of frequency and voltage excursions places the reliability burden solely on transmission entities. This makes is difficult to compensate for the generator's failure to perform and, therefore, is problematic for BES reliability. **The SDT has not seen evidence that lack of ride through capability in existing generation facilities is causing frequent cascading outages. The SDT believes the resources required to retrofit existing plants to meet your recommendation could be better used to improve grid reliability elsewhere.**
Response: Thank you for your comments. Please see responses to specific comments above.		
American Electric Power		1) R1: Should R2, first bullet point exception have a similar counterpart in R1? **The allowance under R2, bullet one, to trip a unit due to SPS operation is characteristic of a system event that would have voltage implications. The SDT is not aware of a SPS scheme that trips due to a frequency initiated event.**

Organization	Yes or No	Question 3 Comment
		2) R2: Does footnote 2 also apply to R2 fourth bullet point? **Footnote 2 is related to existing units, but has been eliminated from the updated standard.** 3) R3: On the last bullet we suggest the word “nameplate” be removed from the sentence. **“Nameplate” is accepted industry terminology for defining the capacity of generating units; therefore, the word will not be removed from the standard.** 4) R5: AEP believes that the requirement of R5 for new units and plants to not trip within the no â€trip zone of Attachment 1 is reasonable, and has precedence in existing reliability region guidelines. To not trip within the no â€trip zone of the Attachment 2 is another matter. AEP maintains that Attachment 2 is inappropriate as a requirement on new conventional generation. When AEP previously raised objection to the reference to Attachment 2 by R5, the SDT replied: "The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain."We note that Order 693, paragraph 1787 does require generation to ride through B and Ccontingencies. However (and we reference the Consideration of Issues and Directives tablea ssociated with PRCâ€024), Order 661 was superceded by 661â€A which removed the voltage rideâ€through curves of the sort as Attachment 2. The SDT is justifying the imposition of an unprecedented (in North America) and onerous requirement on the basis of outdated information. Moreover, the SAR for Project 2007â€09 was a general authorization to proceed with standard development on the subject of generator performance during frequency and voltage excursions, not an authorization to require the specific voltageâ€ride through requirement for new generation now proposed in R5. Please reconsider the justification for this requirement. The SDT further replied: "If the Transmission Planner for a new generation facility can provide the voltage profile for that specific site, then per Part 5.2 the Generator Owner can design his new facility to

Organization	Yes or No	Question 3 Comment
		ride through that profile even if it is less stringent (i.e. uses faster clearing and faster voltage recovery) than Attachment 2. The voltage envelope described in Attachment 2 provides equipment OEM's with an outer boundary on the voltage stress they have to design for. "The exception enabled by the second bullet point of R5 may cause a nonuniform level of reliability. If one transmission planner presents a less stringent voltage rideâ€through characteristic (we assume this would be simulation basedâ€â€R2, Part 2.2 does not exist) to a potential generator than the TP next door, who for lack of time or resources falls back on Attachment 2, then at best, a nonuniform level of reliability would result. Shouldn't there be some uniformity on what generating units are obligated to acheive? We mention this point, not that the exception be removed, but that the requirement of Attachment 2 for new generation, which has not been seen as necessary for reliability in the past, be removed. The SDT further replied to our concern over cost to comply: "There are similar voltage ride through requirements already in effect in parts of Europe and Asia. The SDT is charged with implementing the reliability improvement recommendations from FERC Order 693 and the 2003 Northeast Blackout Report. The SDT agrees that generating units designed and built to meet Requirement R5 will be more costly than those that cannot meet this reliability goal. The SDT is not in a position to place a monetary value on the consequent reliability gain. The SDT is working under the assumption that when industry approved the SAR for this project it agreed that the standard provided a reliability gain. "The SDT is in error in thinking that the reference to Attachment 2 in R5 is necessary to implement Order 693 or to fulfill the intent of the SAR as noted above. We also question the propriety of adding a new reliability standard requirement without precedent in North America irrespective of any consideration of the cost to comply, and a proposed requirement that will certainly act to disfavor new conventional generation compared to what has always been accepted design practice for conventional generation in the past. The SDT needs to provide a relevent technical argument for the new level of reliability and not an appeal to what other parts of the world may be doing. **Based on comments from you and numerous other stakeholders the SDT has**

Organization	Yes or No	Question 3 Comment
		decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. 5) If R5 remains in this standard, its associated measure needs to be changed so that evidence would need to be provided for only those unit trips that occurred during a voltage or frequency excursion. As currently written, evidence would need to be provided for every unit trip, which is both unnecessary and unduly burdensome. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and**

Organization	Yes or No	Question 3 Comment
		generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. 6) R6: As currently drafted, all requests would require continual updates unless otherwise exempted. This should be changed so that all requested are treated as a onetime request unless otherwise specified by the requesting entity. **Response: The SDT thanks you for your comment. The requestor would only be asking for trip settings for those protective functions that are used in the stability model. The requestor would need to know when changes are made to these settings so that his model remains accurate. If it is a one-time study, the requestor has the option of informing the Generator Owner of this at the time of the request per the language in the requirement.**
Response: Thank you for your comments. Please see responses to specific comments above.		
Duke Energy		1) Feedback from the IEEE Electric Machines Committee and Siemens (a generator equipment OEM) serve as the bases for these statements and are included below. PRC-024 was orignially intended to address a relay setting/coordination issue. This appears to be addressed by the current draft of the standard. However, the issues related to plant survivability or performance are more complex. It is not appropriate to attempt to address these issues in a PRC standard. The addition of plant performance aspects appear to be driven by FERC as evidenced by the minutes of the May 2009 meeting - see http://www.nerc.com/docs/standards/dt/GVSDTnotes052809.pdf. **Based on comments from you and numerous other stakeholders the SDT has decided to remove the performance Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders**

Organization	Yes or No	Question 3 Comment
		who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities remote (e.g., more than one bus away) from the fault is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. 2) According to attendees at the IEEE EMC meeting, much of the technical justification for the need of a plant performance criteria was based on issues with early design wind generation, however the technical considerations at these types of generation stations are different that steam turbine generation plants, which require heavy induction loads to support operation. These loads are sensitive to upsets in voltage and frequency. The technical implications of the plant performance are not clear and thus this issues should not be standardized at this point in time. It is recommended that the plant performance aspects be removed from the PRC standard and a new SAR be written to address plant performance requirements. This approach would support pulling in the various design expertise (IEEE, Equipment OEMs, Power Plant Design entities, etc) needed to develop a technically correct ride through criteria. **See response below** 3) There also is a need to develop industry accepted methods to determine the capability of a plant to ride through grid transients prior to this becoming a mandatory standard. **See response below.** 4) It appears the +/- 5 % of the rated generator voltage constraint has been removed

Organization	Yes or No	Question 3 Comment
		from the voltage ride thru criteria. Depending on the tap of the GSU, this might be more limiting than the HVRT curve. SDT should consider keeping the constraint. **The standard is limited to relay settings during the first 4 seconds of a disturbance. Attachment 2 does reference "Return to voltage between 0.95 PU and 1.05 PU dependent on automatic or manual changes to the system."** 5) Related to #5 in the curve clarifications - What is the intend of changing from RMS to crest voltages for the HVRT? What is a crest phase-to-phase voltage? **Clarification #5 addresses concerns raised by equipment manufactures that many types of equipment are more sensitive to the crest voltage than to RMS voltage. Basing the standard only on RMS voltage would require equipment to be designed for unknown conditions.** 6) Related to #6 in the curve clarifications - Voltage relays may not ride through HV or LV disturbances as intended if the curves are not compensated for the rated capabilities of the machine. It would be better to compensate the LVRT curve for operation at the B point on the D-Curve and the HVRT curve for operation at the C point on the D-curve. **The curves are voltage duration envelopes based on transmission system voltages. It is up to the GO to evaluate the generator relay setting based on the range of expected initial conditions to assure that the relays will not operate for the envelope of transmission voltages in Attachment 2.** 7) V/Hz relay should be evaluated in the frequency domain at maximum rated voltage, typically 105%. **The SDT agrees that your suggestion is valid, but would argue that they may be evaluated at 60 Hz with the allowance to operate at proportionally lower voltage with lower frequencies. No change made.** 8) Has any consideration been given to addressing the frequency and voltage excursions in the transmission system in order to arrest the situation locally?

Organization	Yes or No	Question 3 Comment
		The standard applies to Generators Owners. Consideration has been given to transmission system based solutions in R2 where the Transmission Planner can specify less stringent conditions for a specific generator. The UFLS systems designed per standard PRC-006-1 accomplish the suggested activity for frequency excursions. Voltage excursions caused by faults on the transmission system cannot realistically be arrested. 9) Information from IEEE Electric Machinery Committee discussion topic "Grid Code Impact on Electric Machine Design" (San Diego 2012 - Papers from the session with supporting information are available): A) PRC-024 VR capability may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. It is believed the cost of complying with wider standards might increase main generator machine costs as much as 25%, which is not insignificant. This should only be required if there is a defined local system need for higher standards and that these costs should be considered against the cost of other possible resolutions. B) A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of all 4160V and 460V systems in new plant can be dynamically modeled to a degree allowing one to obtain non-drop-out guarantees from equipment suppliers and EPC firms for extreme transients such as 2.0 seconds at 65% voltage, or that the same can be done for existing plants to allow identification of limiting components and accurate estimates of performance. C) The voltage ride through was originally intended to address early deficiencies in wind generation design only and it doesn't make sense to apply such a broad curve to steam plants. The concerns that led to the VRT curve for wind have been addressed by new vintage wind plant designs and thus, the EMC does not believe there is a driving need for a standard VRT criteria. **See response below.**

Organization	Yes or No	Question 3 Comment
		10) The VRT issue is holding up addressing other significant issues addressed by PRC-024 (relay setting coordination and frequency ride through). The VRT should be pulled out of PRC-024 and a new SAR drafted to address the voltage performance aspects if this is really needed for reliability. **See response below.** 11) Information from Siemens (Generator OEM) perspective: A) Regarding PRC-024, the LVRT curves (on Attachment 1) are subject to misinterpretation, since they seem to imply a very slow, stepped voltage recovery rather than a set of roughly equivalent faults. The curve needs some elaboration and supplemental explanation. **Attachment 1 and 2 provide frequency and voltage duration envelopes, not an expected frequency or voltage profile. The curves do not imply a very slow or stepped frequency or voltage recovery. The Clarifications included with the attachment curves provide the requested clarification. See especially Voltage Ride-Through Curve Clarification #3** B) The proposed PRC-024 draft allows certain exemptions (e.g., loss of field and loss of synchronism) that are not permitted in the stability assessment of wind plants. This appears to be in conflict with the FERC 693 mandate for technology-neutral ride-through requirements, since wind turbines have no analogous exceptions. Indeed, the reason for the LVRT standard applied to wind turbines was because of the characteristic of induction generator wind turbines to lose synchronism at low voltages. **The SDT agrees with you fully that wind turbines provide superior reliability benefits for the power system which industry has indicated that conventional generators simply cannot supply. Based on comments from stakeholders the performance requirements that currently apply to wind plants through FERC Order 661 were not extended to conventional generators in this standard.** **R1 provides analogs exemptions for both synchronous and power electronic based equipment.** C) The Abnormal Frequency ride through curves of PRC-024 (on Attachment 2) have

Organization	Yes or No	Question 3 Comment
		not been coordinated with the equipment standards and exceed the overfrequency limits in the equipment standards in most cases. **The Abnormal Frequency ride through curves on Attachment 1 have been adjusted to match IEEE and IEC requirements.** D) Further on PRC-024, there is only one reference explicitly cited, yet there are several implicitly cited (e.g., frequency limits) and there are well-known conflicts with equipment standards. The sources of the frequency limits and equipment standard limits should be cited in publicly available documents. Where, for example, are the Eastern Grid and ERCOT overfrequency requirements? They are not generally known. They should be explicitly cited. **The Abnormal Frequency ride through curves on Attachment 1 have been adjusted to match IEEE and IEC requirements. References for curves have been added to the standard.** E) The LVRT curves stipulate that the stability assessment be performed at rated lagging power factor. This is not a conservative assumption. It should be justified, not simply asserted as standard practice. **It is not the most conservative but it is a typical operating point.**
Response: The SDT thanks you for your comment. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities remote (e.g., more than one bus away) from the fault is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. This directly addresses		

Organization	Yes or No	Question 3 Comment
your comments 2, 3, 9, 10. Please see other responses above.		
Texas Reliability Entity		1) R5: New generation units may not be able to meet this requirement if auxiliary systems are included. While the standard allows for a temporary or retroactive exemption, it is a difficult task to design and build a new plant and take into account the myriad of pumps, fans, dampers, control systems, instrumentation, etc. that could possible trip the unit during a low frequency or low voltage event. The SDT may want to consider removing the language "and plants (including auxiliary systems)" from the first sentence of this requirement. If the SDT maintains this requirement, consideration should be given to utilizing a lower VSL other than Severe. Additionally, considering the proposed definition of BES, is the auxiliary system phrase applicable? **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities remote (e.g., more than one bus away) from the fault is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** 2) As written, the standard will apply across all types of BES-defined generation units

Organization	Yes or No	Question 3 Comment
		(Individual generating unit greater than 20 MVA directly connected to the bulk power system, generating plant/ facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 75 MVA, etc.) regardless of fuel type. Based on this applicability, fossil-fueled conventional units and variable resources (wind, solar, hydro, etc.) must meet the same voltage/frequency criteria. Is this the intent of the SDT? Voltage ride-through capabilities can vary significantly between fossil-fueled plants and wind plants due to their technical dissimilarities. Attempting to apply a single criteria to both will lead to technical difficulties between synchronously-connected and asynchronously-connected machines, as each responds differently voltage disturbances. Attempting a one-size-fits-all approach is inappropriate for this type of standard. The standard should recognize that wind generators and traditional generation facilities are technologically dissimilar and, therefore, cannot be treated the same in this instance. **Yes, the intent of the standard is to be technology neutral and apply to all types of generation, as directed by FERC in Paragraph 1787 of FERC Order 693.** 3) If a Generator Owner has a limitation that is communicated but failed to set its frequency protective relaying to not operate, is that a violation? **The Generator Owner is allowed to set a protective relay to operate within the "No Trip Zone" for that portion of the Zone that applies to the equipment limitation that has been communicated per Requirement R3.** 4) Has there been any consideration of providing separate capability curve figures for each Interconnection? **The SDT considered having separate off-nominal frequency curves for each interconnection but elected to include a single curve in the standard. The individual tables provide more accurate information that would be used for determining relay settings.**
Response: Thank you for your comments. Please see responses to specific comments above.		

Organization	Yes or No	Question 3 Comment
Wisconsin Electric Power Company		1. In R2, it is not specified whether the voltage ride-through curve (Attachment 2) refers to three-phase voltages or any one phase. This makes an enormous difference in the ability of equipment to withstand the sag. More importantly, the extreme voltage ride through requirements do not appear to be technically feasible to achieve for coal and gas-fired turbine-generators. The voltage ride-through requirements should be re-examined to verify they are justified by reliability need, and separated from the more critical frequency coordination requirements. We believe that a separate standard is needed for the voltage requirements, which are not as clearly justified or supported by existing equipment. **The voltage ride-through curves are voltage magnitude vs. duration which would encompass both three-phase and single-phase faults on the transmission system. The duration of the curves in Attachment 2 has been shortened form 10 minutes to 4 seconds to coordinate with the Generator Relay Loadability standard (PRC-025). Following the excursion defined in PRC-024 Attachment 2, the steady-state stressed system conditions described in PRC-025 would apply. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard, eliminating the voltage ride through performance requirement for future generating facilities.** 2. R2 consists of a single sentence with over 100 words. This needs to be corrected. **The SDT feels that R2 is clearly written and expresses the reliability objective.** 3. In R3 and associated M3, the GO is responsible to document equipment limitations that prevent the unit from meeting the frequency and voltage performance curves. However, it is not uncommon for the generating unit to experience problems in a wide variety of plant systems which result in unit trips. Thus the GO is not necessarily aware of the source of these less frequent unit trips caused by external events, such as transmission system faults, and associated voltage sags. Therefore this requirement needs to also apply to the Transmission Owner. The TO (or TP) should be required to identify those events within its system that may

Organization	Yes or No	Question 3 Comment
		have adversely affected generating units. Only then can the GO be responsible to identity its equipment limitations. Without this joint responsibility, this requirement should be removed. **The GO is responsible for documenting equipment limitations that require generator protection to be set to operate within the "No Trip Zone" of Attachments 1 or 2 based on the frequency and voltage at the point of interconnection regardless of the transmission system event which caused the voltage or frequency deviation. The Transmission Owner and Transmission Planner do not have the information about the Generator Owners' equipment to make the assessment being recommended. This has always been the responsibility of the Generator Owner.** 4. In R3.1, the requirement is for the GO to communicate equipment limitations to four different entities. This requirement is in the long-term planning horizon, and therefore the communication should be limited to the TP only, and not the other entities. The TP is the primary recipient, and they can pass the information to the other entities as necessary, as described in the NERC Functional Model. In addition, the time requirement of 30 days is unreasonably short; we suggest that 90 days would be sufficient for this long-term planning requirement. **The SDT feels that 30 days is a reasonable amount of time to compile and send the required information and that sending the material to the four entities is not an unreasonable burden.** 5. In R5, it does not appear that new thermal plants can meet these requirements, which have largely been developed for wind farms, especially Attachment 2. The auxiliary systems of such plants cannot be quaranteed to meet the performance curves, apart from a strong cooperative effort by equipment suppliers to design these requirements into the equipment. There need to be industry standards (e.g., IEEE) in place before this requirement is ready for industry use, such as performance standards for equipment like variable-speed drives, for one example.

Organization	Yes or No	Question 3 Comment
		Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities remote (e.g., more than one bus away) from the fault is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.
Response: The SDT thanks you for your comment. Please see responses above.		
Tennessee Valley Authority		1. The technical justification for the need of a plant performance criteria appears to be based on issues with early design wind generation. The technical considerations at these types of generation stations are different than steam turbine generation plants, which require heavy induction loads to support operation and these loads are sensitive to upsets in voltage and frequency. The technical implications of the plant performance are not clear. Recommend generating a separate SAR and bring in industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical acadamia, etc. to assist in the technical analysis and standard development.

Organization	Yes or No	Question 3 Comment
		2. Likewise, industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical acadamia, etc. can develop acceptable methods to determine the capability of a plant to ride through grid transients. 3. The following are IEEE Electric Machines Committee comments for PRC-024-1 considerationThe IEEE Electric Machinery Committee hosted a discussion topic on “Grid Code Impact on Electric Machine Design” in San Diego at this year’s Power Engineering Society meeting and offers the following input. o Minor changes in the Under-frequency Ride Through Curve are suggested to better match existing machine design standards in IEEE C50????. o The PRC-024 Voltage Ride Through criteria is technically not ready to be a standard, for the following reasons; 1. PRC-024 VR capability may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. It is believed the cost of complying with wider standards might increase main generator machine costs as much as 25%, which is not insignificant. This should only be required if there is a defined local system need for higher standards and that these costs should be considered against the cost of other possible resolutions. 2. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of all 4160V and 460V systems in new plant can be dynamically modeled to a degree allowing one to obtain non-drop-out guarantees from equipment suppliers and EPC firms for extreme transients such as 2.0 seconds at 65% voltage, or that the same can be done for existing plants to allow identification of limiting components and accurate estimates of performance. 3. The voltage ride through was originally intended to address early deficiencies in wind generation design only and it doesn’t make sense to apply such a broad curve to steam plants. The concerns that led to the VRT curve for wind have been addressed by new vintage wind plant designs and thus, the EMC does not

Organization	Yes or No	Question 3 Comment
		believe there is not driving need for a standard VRT criteria. o The VRT issue is holding up addressing other significant issues addressed by PRC-024 (relay setting coordination and frequency ride through). The VRT should be pulled out of PRC-024 and a new SAR drafted to address the voltage performance aspects if this is really needed for reliability. o More clarity in defining plant MVARs available to support grid voltage is needed. Specifically, generation plants have not been designed to operate outside a normal band of 95 to 105% on the generator terminals. GSU settings are typically chosen to optimize MVAR support under normal operations, however is not reasonable to assume the full leading or lagging reactive support would be available under normal grid conditions.
Response: The SDT thanks you for your comments. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities remote (e.g., more than one bus away) from the fault is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. The Abnormal Frequency ride-through curves on Attachment 1 have been adjusted to match IEEE and IEC requirements. References for curves have been added to the standard.		
Independent Electricity System Operator		1. We appreciate the SDT's effort in making clarifying changes to the Implementation Plan to separate the effective dates for jurisdictions where regulatory is and isn't required. And we understand that the phrase "following applicable regulatory authority" includes regulatory bodies from Canadian provinces requiring regulatory body approval. However, the separation alone and leaving the phrase "following

Organization	Yes or No	Question 3 Comment
		applicable regulatory authority" unchanged do not address the situation in Ontario where (a) regulatory approval is required" but (b) the effective dates are not necessarily tied with the effective dates indicated in the Sub-Section that applies to those jurisdictions where regulatory is required. In other words, the proposed language only partially reflects Canadian regulatory framework and we suggest additional wording, as described below. We request the following phrase be added to each sentence under the "In those jurisdictions where regulatory approval is required" of the Implementation Plan: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." right after "following applicable regulatory approval". The revised first bullet, for example, will read: o By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R6. And the same change to each of the sentences in Section A5.1 of the standard should also be made. **The SDT agrees with your suggestion and has included the requested language.** 2. The impact of disconnecting a generating unit less than 20 MVA or a generation plant less than 75 MVA during frequency or voltage excursions is very limited. We suggest to add the following facility thresholds into the applicability section: a. Generating unit with a gross nameplate rating greater than 20 MVA b. Generating plant with an aggregated gross nameplate rating greater than 75 MVA **The applicability for this standard is based on the Registry Criteria, so your suggested change is already included.** 3. There is a typo on the R2 footnote on "protective relaying". It should be 2 instead of 1. **This is supposed to be the same footnote as in R1, as it applies to both requirements.**

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. Please see responses above.		
Essential Power, LLC		1.The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1 are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions that are unsafe. **R3 allows the GO to document, and provide to the documentation to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner, the known equipment limitations which will not allow the equipment to meet the criteria of Attachments 1 and 2. This allows the Generator Owner to set protection to trip the generator inside the "No Trip Zone" for the specific limitations communicated. These would include both of your examples (protecting the turbine from operating at low frequencies that the OEM has specified will damage the turbine and for operating under conditions prohibited by the NRC).** 2.Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. **When the upsets described above can be proven as true limitations, then R3 allows the GO to document, and provide to the documentation to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner, the known equipment limitations which will not allow the equipment to meet the criteria of Attachments 1 and 2.** 3.Auxiliary equipment contactors are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses. **Auxiliary equipment contactors are not considered part of the generator protection as defined for Requirements R1 and R2 in this standard. The Generator Owner will need to take into consideration the performance of this equipment during voltage or frequency excursions only if requested to provide the estimate contained in**

Organization	Yes or No	Question 3 Comment
		Requirement R4. 4.Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. **While frequency and voltage protective relaying or functions will be set per Attachments 1 and 2 of PRC-024-1, the GO will need to take into consideration the above mentioned equipment only if requested to provide the estimate contained in R4.** 5. The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to "protective relaying," which per footnote #1 in PRC-024 includes "protective functions within control systems...based on frequency or voltage inputs." It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions**. The definition of protective relaying and protective functions does not cover contactor drop-out or actuation of fan stall protection systems.** 6.The basis of compliance for new units is simply, "will not trip," i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting-down the new power plant industry unless an owner were willing to take unbounded risk**. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify**

Organization	Yes or No	Question 3 Comment
		the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. 7. A “will not trip” obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. It is noteworthy in this respect that environmental regulators have for decades been pushing gas turbine dry low-NOx combustors to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances. Greater consideration of BES reliability may be needed, but doing so by issuing dueling regulations would not constitute an appropriate approach**. See answer to 6 regarding the removal of R5 from the previously posted standard.** 8. M5 causes new-unit tripping due to frequency or voltage excursions within PRC-024 limits to constitute a violation, but it seems unlikely to expect an “or” event. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 in this standard. **See answer to 6 regarding the removal of R5 from the previously posted standard.** 9. The grandfathering of existing units in R1 and R2 for, “documented and communicated equipment limitations,” is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations and the like during Disturbances

Organization	Yes or No	Question 3 Comment
		will not be defined in OEM literature, nor is it generally possible to predict by calculations when such problems will occur, especially if a Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true regarding predicting transient fluctuations of aux bus voltages, ref. risk of contactor drop-out and stalling major auxiliary equipment. **The exemptions in requirement R3 based on requirement R1 and R2 relay settings apply only to equipment protected by generator protective relaying and not relaying associated with in-plant equipment.** 10. The concern above applies also to having to make reference per R3 to, "study results, experience from an actual event, or manufacturers advisory." Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1 and Att. 2. The list of types of evidence in R3 is not exclusive, but it is difficult to imagine alternative forms of hard evidence that could be developed other than for the comparatively few plants that possess high-fidelity simulators. **The generator owner will be required to support the exemption by documentation but this only applies to equipment that is protected by generator protective relaying only. The equipment manufacturer should provide operating limitation documentation with the equipment.** 11. The same concerns regarding availability of information apply for the, "estimate of the time duration the existing generation unit will remain connected," in R4. Relying on "sound engineering judgment" is permitted, and R4 states that "detailed unit performance studies are not required;" but the word "sound" implies that the estimate is to be based on accurate data, and how such information could be developed without a detailed study is unclear. **Requirement R4 was worded to address the concern that detailed studies are not required. The entity should use available data and its knowledge of the plant design to develop an estimate.** 12. Confusion is created by making grandfathering, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such protective relays meant

Organization	Yes or No	Question 3 Comment
		to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any grandfathering is actually being allowed. **The exemptions in requirement R3 are based on the inability of a generating unit meeting the criteria in Requirements R1 or R2. Inability to set existing protection to meet these Requirements does not constitute a valid reason for setting the protection to trip the generator within the no-trip zone in Attachments 1 and 2.** 13. The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. **If an entity replaces a piece of equipment that is causing a limitation per Requirement R3 and increases capacity by 10%, it must address the limitations. This is analogous to New Source Standards for pollution control.** 14. Steam turbine off-frequency limits are generally set by OEMs lifetime limits as regards duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated. **The drafting team realizes that multiple under/over frequency events may occur that result is turbine blade loss of life resulting in an entity changing relay settings that effectively allows for tripping in the no trip zone. If this were to occur, the entity would supply documentation that supports exemption in requirement R3.** 15. An additional "may trip" exclusion is needed for R1 and R2 related to V/Hz set properly to limit over excitation of generators or transformers. **Volts per hertz relaying is evaluated in requirement R2 as a voltage relay with a constant 60 hertz frequency. Per Clarification #4, the high voltage portion of the curves in Attachment 2 should be lowered proportionately for evaluating at frequencies lower than 60 Hz.** 16. Objection to R5 - the additional costs involved for re-designing generating stations so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability

Organization	Yes or No	Question 3 Comment
		of a voltage and/or frequency excursion occurring. Furthermore, we believe it is fundamentally inappropriate to support approval of such a requirement until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved. We recommend this requirement be removed so the standard can move forward to address the shorter term goals that are achievable. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** 17. Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Also, this requirement may repeat requirements that are being developed in revisions to PRC-001. **Although unlikely, there may be cases where a planner may require relay settings from other generator protective functions to perform studies. It is to the Generator Owner's advantage with little burden to provide such data for a Transmission Planner's study to be as accurate as possible.** 18. It is inconceivable that most plants can ride through a + or - 10% voltage

Organization	Yes or No	Question 3 Comment
		excursion for 10 minutes per PRC-024, Attachment 2. Almost all would have to take exceptions. **The curves in Attachment 2 have been revised and shortened from 600 seconds to 4 seconds in order to coordinate better with the Generator Relay Loadability standard (PRC-025). The philosophy is that PRC-024 applies during excursions and PRC-025 applies subsequently during steady-state stressed system conditions.**
Response: The SDT thanks you for your comments. See individual responses to your questions above.		
Pepco Holdings Inc		A footnote 2 reference to qualify the term "existing generating unit" should also be included in the last bullet in Requirement R2.Also, the language in footnote 2 should begin with "Includes ..." rather than "To include..."
Response: The SDT thanks you for your comments. Due to the SDT removing the ride-thru provisions of R5 in the previously posted version of this standard, the term "existing generating unit" and the footnote has been removed from the next draft.		
SERC Reliability Corp		An additional "may trip" exclusion is needed for R1 and R2 related to properly set V/Hz relaying. **The SDT reviewed IEEE standards and published OEM V/Hz capabilities and believes that the high voltage curve (in conjunction with Clarification #4) allow V/Hz protection to be set to protect the equipment while still meeting the requirements of this standard without additional exclusions .** Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Note: Depending on approval dates, R6 may repeat requirements that are being developed in revisions to PRC-001 and/or PRC-027. **The GO must provide all requested protective settings. These settings would be those that are included in the planner's stability models. It is important for grid stability that these stability models contain accurate information. The SDT does not see this as an undue burden. No such settings reporting requirements exist in PRC-001 or PRC-027.**

Organization	Yes or No	Question 3 Comment
		Not really protection related: The additional costs involved for re-designing generating stations under R5 so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability of a voltage and/or frequency excursion occurring. It is inappropriate to support approval of such a requirement until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.**
Response: The SDT thanks you for your comments. See individual responses to your questions above.		
Southern Company		1) An additional “may trip” exclusion is needed for R1 and R2 related to V/Hz set properly to limit overexcitation of generators or transformers. **The SDT reviewed IEEE standards and published OEM V/Hz capabilities and believes that the high voltage curve (in conjunction with Clarification #4) allow V/Hz protection to be set to protect the equipment while still meeting the requirements of this standard**

Organization	Yes or No	Question 3 Comment
		without additional exclusions . 2) Please consider a requirement for the TP to perform location-specific system voltage recovery studies referenced in R2. This should be a requirement for the TP prior to requiring the severe voltage profile of Attachment 2. **The SDT feels the profile of Attachment 2 can be accomplished by the vast majority of applicable generating units. The GO may request the voltage recovery characteristics of a location-specific Transmission Planner's study for any generating unit.** 3) Both the exemption of existing units using the exceptions in R1 and R2 for "documented and communicated equipment limitations" and "the estimation of time a unit will remain connected" per R4 are problematical. Power plants exhibit a tendency for have drum level fluctuations, air/flue gas flow oscillations, or other plant subsystem instability during system disturbances which are not defined in OEM literature. It is generally not possible to determine when such problems will occur especially if a disturbance involves cycling above and below the rated frequency within the Attachment 1 boundaries. The same is true regarding predicting transient fluctuations of auxiliary system bus voltages. These voltage fluctuations affect power distribution equipment in the power plant by contactor or control relay drop-out, major auxiliary equipment stalls, etc. Predicting when a plant trip will occur due to these types of power plant system responses is problematic. **The SDT agrees with your comment, but believes that the wording of R4, "The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment," allows the GO to provide an estimate.** 4) The "10% power increase" exemption loss (in the last bullet item of R3.1) may effectively ban entire classes of equipment or prevent units from ever receiving capacity and efficiency enhancements. . **If an entity replaces a piece of equipment that is causing a limitation per Requirement R3 and increases capacity by 10%, it must address the limitations. This is analogous to New Source Standards for pollution control.** 5) We object to R5 - the additional costs involved for re-designing generating stations

Organization	Yes or No	Question 3 Comment
		so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability of a voltage and/or frequency excursion occurring. Furthermore, we believe it is fundamentally inappropriate to support approval of such a requirement until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved. We recommend this requirement be removed so the standard can move forward to address the shorter term goals that are achievable. Further commentsi regarding R5: Currently, there exist too many engineering challenges to permit the requirement of R5. These include the following:Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable.Auxiliary equipment contactors and energized control relays are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses. This dropout will occur within a few cycles.The basis of compliance for new units is simply, “will not trip,” i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting-down the new powerplant industry unless an owner were willing to take unbounded risk. This will require revision of, not only plant equipment standards, but “plant system” standards. Even if we could certify all of the components, you cannot guarantee once they are implemented into a system they will respond as planned. Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 in this standard.The SDT stated in

Organization	Yes or No	Question 3 Comment
		their previous PRC-024 Consideration of Comments that grid requirements similar to R5 are already in effect in parts of Europe. U.S. standards still prevail for design, construction, and operation of plants in the U.S. We believe it is inappropriate to implement a national standard requiring U.S. plants be designed to the requirements of R5 until the industry can demonstrate through additional research, development, and revision of the plant equipment and system standards that such requirements can be practically met. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** 6) Please consider requirements for TO to address the frequency and voltage excursions in the transmission system in order to arrest the abnormal condition locally. **The standard applies to Generators Owners. Consideration has been given to transmission system based solutions in R2 where the Transmission Planner can specify less stringent conditions for a specific generator. The UFLS systems designed per standard PRC-006-1 accomplish the suggested activity for frequency excursions. Voltage excursions caused by faults on the transmission system cannot**

Organization	Yes or No	Question 3 Comment
		realistically be arrested. 7) Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Also , this requirement may repeat requirements that are being developed in revisions to PRC-001. **The GO must provide all requested protective settings. These settings would be those that are included in the planner's stability models. It is important for grid stability that these stability models contain accurate information. The SDT does not see this as an undue burden. No such settings reporting requirements exist in PRC-001 or PRC-027.** 8) It is inconceivable that most plants can ride through a + or - 10% voltage excursion for 10 minutes per PRC-024, Attachment 2. Almost all would have to take exception. All of our nuclear plants would trip as would the new nuclear plant currently under construction. **The curves in Attachment 2 have been revised and shortened from 600 seconds to 4 seconds in order to coordinate better with the Generator Relay Loadability standard (PRC-025). The philosophy is that PRC-024 applies during excursions and PRC-025 applies subsequently during steady-state stressed system conditions.**
Response: The SDT thanks you for your comments. See individual responses to your questions above.		
BrightSource Energy		BrightSource is voting affirmative with the understanding that individual Regions can have requirements that are more stringent than NERC Standards. Therefore, even though R3 only requires GOs to "document each known equipment limitation (excluding limitations that are caused by generator frequency and voltage protective relays) that prevents a generating unit, from meeting the criteria in Requirements R1 or R2 ....", it does not relieve the GOs of their obligations under the WECC Coordinated Off-Nominal Load Shedding Plan for generators that connects to the Western Interconnection.
Response: The SDT thanks you for your comment and agrees with its content.		

Organization	Yes or No	Question 3 Comment
Consumers Energy		Consumers Energy's previous comments - "Related to undervoltage criteria, the 18 cycle at 45% of generator voltage would put a great deal of strain on the plant auxiliary systems and that may not be something these systems are able to withstand. The same would be true of a fault that produces 65% voltage at the generator terminals for 2 seconds. These comments relate specifically to Consumers Energy. However, it is likely that many others have similar equipment and would have the same issues. Please also note that the proposed standard does not align with ANSI C37.102, IEEE Guide for AC Generator Protection or with the NERC Technical Reference Document entitled Power Plant and Transmission System Protection Coordination."Previous SDT reply - Thank you for your comments. Please note that the voltage levels specified in Attachment 2 are at the point of interconnection to the transmission system. They would not correlate directly with the auxiliary bus voltages, especially if the auxiliaries are unit-connected. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. Please inform the SDT of the specifics of your concerns." We believe our comments still apply. Specific to the fault that produces 65% voltage at the generator terminals for 2 seconds, plant auxliary equipment would not be able to withstand such a drop for the specified duration and would fall offline.
Response: The SDT thanks you for your comments. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. The SDT believes that the wording of R4, "The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment," will allow the GO to provide an estimate. However, if the GO feels his equipment is not capable of meeting the undervoltage criteria of Attachment 2, then R3 would apply. Also, note that Attachment 2 has been modified for the next draft and now only extends to 4 seconds.		
Cowlitz PUD		Cowlitz supports the comments from the NAGF SRT: 1. The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1 are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions

Organization	Yes or No	Question 3 Comment
		that are unsafe. **Requirement R3 allows the GO to document, and provide to the documentation to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner, the known equipment limitations which require generator protection to be set to trip inside the no-trip zone of Attachments 1 and 2.** 2. Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. **Requirement R3 allows the GO to document, and provide to the documentation to the Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner, the known equipment limitations which require generator protection to be set to trip inside the no-trip zone of Attachments 1 and 2.** 3. Auxiliary equipment contactors are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses. **Auxiliary equipment contactors are not considered part of the generator protection as defined for Requirements R1 and R2 in this standard. The Generator Owner will need to take into consideration the performance of this equipment during voltage or frequency excursions only if requested to provide the estimate contained in Requirement R4** 4. Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. **Fans and pumps are not considered part of the generator protection as defined for Requirements R1 and R2 in this standard. The Generator Owner will need to take**

Organization	Yes or No	Question 3 Comment
		into consideration the performance of this equipment during voltage or frequency excursions only if requested to provide the estimate contained in Requirement R4. 5. The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to "protective relaying," which per footnote #1 in PRC-024 includes "protective functions within control systems...based on frequency or voltage inputs." It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions. **The definition of protective relaying and protective functions does not cover contactor drop-out or actuation of fan stall protection systems.** 6. The basis of compliance for new units is simply, "will not trip," i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting down the new power plant industry unless an owner is willing to take unbounded risk. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While**

Organization	Yes or No	Question 3 Comment
		there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. 7. A "will not trip" obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. It is noteworthy in this respect that environmental regulators have for decades been pushing gas turbine dry low-NOx combustors to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances. Greater consideration of BES reliability may be needed, but doing so by issuing dueling regulations would not constitute an appropriate approach. **See answer to 6 regarding the removal of R5 from the previously posted standard.** 8. M5 causes new-unit tripping due to frequency or voltage excursions within PRC-024 limits to constitute a violation, but it seems unlikely to expect an "or" event. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 in this standard. **See answer to 6 regarding the removal of R5 from the previously posted standard.** 9. The grandfathering of existing units in R1 and R2 for, "documented and communicated equipment limitations," is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations and the like during Disturbances will not be defined in OEM literature, nor is it generally possible to predict by calculations when such problems will occur, especially if a Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true regarding predicting transient fluctuations of aux bus voltages, ref. risk of contactor drop-out and stalling major auxiliary equipment. **The exemptions in requirement R3 based on requirement R1 and R2 relay settings**

Organization	Yes or No	Question 3 Comment
		apply only to equipment protected by generator protective relaying and not relaying associated with in-plant equipment. 10. The concern above applies also to having to make reference per R3 to, "study results, experience from an actual event, or manufacturers advisory." Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1 and Att. 2. The list of types of evidence in R3 is not exclusive, but it is difficult to imagine alternative forms of hard evidence that could be developed other than for the comparatively few plants that possess high-fidelity simulators. **The SDT believes this would typically apply to limitations documented by OEM bulletins or by regulatory (e.g., NRC) operating restrictions which are generally available to Generator Owners. A Generator Owner may have performed a finite element analysis of a set of turbine blades to determine off-nominal frequency capability. While the SDT acknowledges this would be unusual, the intent of the wording in Requirement R3 was not to limit the type of evidence.** 11. The same concerns regarding availability of information apply for the, "estimate of the time duration the existing generation unit will remain connected," in R4. Relying on "sound engineering judgment" is permitted, and R4 states that "detailed unit performance studies are not required;" but the word "sound" implies that the estimate is to be based on accurate data, and how such information could be developed without a detailed study is unclear. **Requirement R4 was written to address the concern that detailed studies are not required. The entity should use available data and its knowledge of the plant design to develop an estimate.** 12. Confusion is created by making grandfathering, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such protective relays meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any grandfathering is actually being allowed.

Organization	Yes or No	Question 3 Comment
		The exemptions in requirement R3 are based on the inability of a generating unit meeting the criteria in Requirements R1 or R2. Inability to set existing protection to meet these Requirements does not constitute a valid reason for setting the protection to trip the generator within the no-trip zone in Attachments 1 and 2. 13. The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. **If an entity replaces a piece of equipment that is causing a limitation per Requirement R3 and increases capacity by 10%, it must address the limitations. This is analogous to New Source Standards for pollution control.** 14. Steam turbine off-frequency limits are generally set by OEMs lifetime limits as regards duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated. **The drafting team realizes that multiple under/over frequency events may occur that result is turbine blade loss of life resulting in an entity changing relay settings that effectively allows for tripping in the no trip zone. If this were to occur, the entity would supply documentation that supports exemption in requirement R3.** 15. An additional “may trip” exclusion is needed for R1 and R2 related to V/Hz set properly to limit over excitation of generators or transformers. **Volts per hertz relaying is evaluated in requirement R2 as a voltage relay with a constant 60 hertz frequency. If the relay cannot be set according to Attachment 2, an exemption is allowed using requirement R3.** 16. Objection to R5 - the additional costs involved for re-designing generating stations so that every control subsystem can ride through the excursions defined by the attached curves is not economically justifiable considering the very small probability of a voltage and/or frequency excursion occurring. Furthermore, we believe it is fundamentally inappropriate to support approval of such a requirement

Organization	Yes or No	Question 3 Comment
		until the technical issues that would require changes to the industry standards for plant systems and equipment are resolved. We recommend this requirement be removed so the standard can move forward to address the shorter term goals that are achievable. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** 17. Does R6 refer to ALL generator trips? This should be limited to Protection System relaying set to trip on over/under voltage or over/under frequency, or over volts/Hertz, not ALL generator trips. Also, this requirement may repeat requirements that are being developed in revisions to PRC-001. **Although unlikely, there may be cases where a planner may require relay settings from other generator protective functions to perform studies. It is to the Generator Owner's advantage with no undue burden to provide such data for a Transmission Planner's study to be as accurate as possible.** 18. It is inconceivable that most plants can ride through a + or - 10% voltage

Organization	Yes or No	Question 3 Comment
		excursion for 10 minutes per PRC-024, Attachment 2. Almost all would have to take exception. **Requirement R4 has been revised and the reference to 10 minutes has been removed.**
Response: The drafting team thanks you for your comments. Please see the answers to each comment above.		
Exelon Corporation and its affiliates		1) Exelon is concerned that there are no set criteria for the transients nor any guidelines in the Standard on the number of requests that the RC, PC, TOP or TP could ask for. This is problematic in that the generating units could be subject to multiple requests for different combinations of transients without any cost benefit or justification. Exelon therefore suggests that the GVSDT evaluate adding language to the Standard that includes a provision for a set periodicity in which the transmission entities can request such data (e.g., an annual request or following a significant event on the transmission system). **Requirement R4 was revised that requests may only be sent from a Planning Coordinator or Transmission Planner. In the event that multiple requests are received, it is permissible to use the initial response for each request.** 2) Exelon previously requested that the GVSDT split the Off Normal Frequency Capability Curve (Attachment 1) be split into separate tables for each Interconnect to make it easier to read. The response from the GVSDT states that they do not believe adding more graphs would add clarification since there are separate data tables. Although Exelon agrees that you could reference the data tables to ensure you are following the correct curve; unless the Off Normal Frequency Capability Curve is printed in color it is difficult to distinguish which line corresponds to which interconnection. Exelon still maintains that for clarity that each data table for each Interconnection should have a separate corresponding graph. **The drafting team realizes that the frequency graph may be difficult to follow but**

Organization	Yes or No	Question 3 Comment
		believes that adding the table to assist in clarifying the data points alleviates the need for multiple graphs.
Response: The drafting team thanks you for your comments. Please see the answers to each comment above.		
Omaha Public Power District		Footnote 1, which is referenced in R1 and R2, has two separate purposes: one is to provide a definition of frequency or voltage protective relaying, and the other is to state that each Generator Owner is not required to have frequency or voltage protective relaying installed or activated on its unit. Accordingly, it should be split into two separate sentences. We recommend that Footnote 1 be replaced by the following paragraph: Frequency or voltage protective relaying includes but is not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency, speed, or voltage inputs. Each Generator Owner is not required to have frequency or voltage protective relaying installed or activated on its unit. Note the addition of the word “speed” in the definition of frequency or voltage protective relaying.
Response: The drafting team thanks you for your comment. The drafting team believes that the footnote has sufficient clarity on examples of relays included in the standard and an entity is not required to install or activate any of the protective functions.		
Wolverine Power Cooperative		I would recommend that the standard applicability be narrowed to BES units only. The way I read the standard draft it would apply to all generating units. This seems to be a significant cost and amount of work for smaller units that will not have a great impact on the BES. I would suggest that in the applicability section of the standard that the BES unit definitions be used (greater than 85MVA, connected >100kV, etc).
Response: The drafting team thanks you for your comment. The drafting team believes that all units without exception for a registered Generation Owner are required to comply with this standard.		

Organization	Yes or No	Question 3 Comment
American Transmission Company		In Requirement 3.1 - ATC recommends replacing the wording of "shall communicate the documented equipment limitation" with "shall communicate the documented equipment limitation and the expected duration of the limitation, if it is known". The addition of expected limitation duration could be valuable reliability information.
Response: The drafting team thanks you for your comment. The SDT believes that in the vast majority of cases, the limitations are effectively permanent so providing information on the expected duration would be of little value.		
Ingleside Cogeneration LP (voting under entity name Occidental Chemical Corporation)		Ingleside Cogeneration LP agrees that Transmission Planners and other operating entities must be able to rely on a generator's availability when voltage and frequency transients occur at the interconnection point. However, we are not convinced that the project teams assertion that all technologies can accommodate the ride-through thresholds posed in PRC-024-1 R5 simply because some European nations already require them. This trivializes a major concern that a generator and all its auxiliary systems must remain online while severe stress is imposed upon mechanical systems spinning at high speeds. Our vendors are telling us that they don't know if they can accommodate the specified thresholds - and they have decades of engineering experience behind their assessments. In addition, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as results that demonstrate compliance. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence**

Organization	Yes or No	Question 3 Comment
		of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements that look for evidence that a unit does not trip in response to a transient (R5) must contain language that focuses on the strength of the process - not the actual performance. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will automatically assess a violation regardless of whether the trip was necessary to protect equipment or safety. The CEA's focus needs to be on the entity's commitment to establishing the necessary ride-through settings over the longer term. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects. **Your issues (1 & 2 above) relate to the "Find, Fix and Track" process that was**

Organization	Yes or No	Question 3 Comment
		most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states:"Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that *identifies, assesses, and corrects deficiencies*, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months:" This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of PCR-024 are to ensure that generators remain in service during frequency and voltage excursions and providing others with information about limitations. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.
Response: The drafting team thanks you for your comments. Please see the answers to each comment above.		
JEA		JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Response: The SDT thanks you for your comment. No such request for a joint meeting has been received by the SDT. However, based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on		

Organization	Yes or No	Question 3 Comment
the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.		
PPL Corporation NERC Registered Affiliates		1) Looking at the Table for the Eastern Interconnection in Attachment 1 of the Standard, this table does not correlate to our company procedures for EOP-003, in which generators are expected to isolate from the system anytime the frequency goes to 58.2 Hz or lower. The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1 are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions that are unsafe. Please see in this respect the SERC Generation Subcommittee Nuclear Plant Review of PRC-024 Curves presentation made at the SERC Engineering Committee Meeting of March 16, 2011 at Charlotte, NC. **Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 or Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3.** 2) Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. See also in this respect the AREVA NP White Paper on PRC-24.Auxiliary equipment contactors are likely to drop-out at the off-design voltage values specified in Att. 2 of PRC-024-1, especially if the high-side voltage swings specified in this standard are magnified at plant MV and LV aux buses.Fan and pump performance will be affected at the frequency limits of Att. 1, and below-rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but

Organization	Yes or No	Question 3 Comment
		within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to “protective relaying,” which per footnote #1 in PRC-024 includes “protective functions within control systems...based on frequency or voltage inputs.” It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions .The basis of compliance for new units is simply, “will not trip,” i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2, effectively shutting-down the new power plant industry unless an owner were willing to take unbounded risk. A “will not trip” obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. “It is noteworthy in this respect that environmental regulators have for decades been tightening gas turbine dry low-NOx combustor emissions limits, taking these devices to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances, and there were in fact many gas turbine flame-out trips during the blackout of ‘03. That is, the EPA and NERC may be trying to achieve divergent and even incompatible goals, so merely allowing time for development of new designs is not a solution. NERC, NAGF, the EPA, OEMs and industry groups should develop a mutually acceptable set of performance requirements.” **Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 or Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3.** 3) M5 causes new-unit tripping due to frequency or voltage excursions within PRC-

Organization	Yes or No	Question 3 Comment
		024 limits to constitute a violation, but it seems unlikely to expect an "or" event. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors will be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 in this standard. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** 4) The grandfathering of existing units in R1 and R2 for, "documented and communicated equipment limitations," is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations and the like during Disturbances will not be defined in OEM literature, nor is it generally possible to predict by calculations when such problems will occur, especially if a Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true regarding predicting transient fluctuations of aux bus voltages, ref. risk of contactor drop-out and stalling major auxiliary equipment. The concern above applies also to having to make reference per R3

Organization	Yes or No	Question 3 Comment
		to, "study results, experience from an actual event, or manufacturer's advisory." Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1 and Att. 2. The list of types of evidence in R3 is not exclusive, but it is difficult to imagine alternative forms of hard evidence that could be developed other than for the comparatively few plants that possess high-fidelity simulators. **R1, R2, and R3 now apply to all units, existing and new. R5, previously written for "new" units, has been deleted.** 5) Confusion is created by making grandfathering, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such protective relays meant to correspond to the "protective relaying" discussed above? It is unclear whether or not any grandfathering is actually being allowed. **The exclusion of the relays listed is so that they alone are not allowed to be the reason that the unit is permitted to trip.** 6) The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. Steam turbine off-frequency limits are generally set by OEMs lifetime limits as regards duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated. **If an entity replaces a piece of equipment that is causing a limitation per Requirement R3 and increases capacity by 10%, it must address the limitations. This is analogous to New Source Standards for pollution control.**
Response: Thank you for your comments. Please find responses to your individual comments above.		

Organization	Yes or No	Question 3 Comment
Cogentrix Energy		1) Project 2007-09 Generator Verification includes draft standard PRC-024, Generator Performance During Frequency and Voltage Excursions. Requirements R3 and R4 are for existing generating units. R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented cases where generator protective relaying cannot be set, and directs those generators to communicate that limitation to the RC, PC, TOP and TP so its performance can be modeled correctly. R4requires a Generator Owner to estimate the time duration for remaining on-line based on a Transmission Planner's dynamic study. Requirement R5 directs all new generating facilities to be designed, built and maintained so that they are able to ride through the excursions defined in Attachment 1 and 2.Voltage Ride-Through Background In FERC Order 661 (June 2, 2005), Final Rule on Interconnection for Wind Energy, the Commission adopted a low voltage ride-through standard for wind generators, but provided that a wind plant is required to meet the standard only if the Transmission Provider shows, in the System Impact Study, that low voltage ride-through capability is needed to ensure safety or reliability. The standard, if applicable, requires the wind generator to stay online for specified time periods and at associated voltage levels where there is a disturbance on the transmission system. Several entities requested rehearing of various aspects of the low voltage ride-through requirement and standard included in the Final Rule. In FERC Order 661-A (December12, 2005) page 2, the Commission noted "that the standard interconnection procedures and agreement were based on the needs of traditional generation facilities and that a different approach might be more appropriate for generators relying on other technologies, such as wind plants. Accordingly, the Commission granted certain clarifications, and also added a blank Appendix G to the standard Large Generation Interconnection Agreement (LGIA) for future adoption of requirements specific to other technologies." The Commission went on to adopt in Appendix G to the LGIP limited special interconnection procedures applicable to wind plants only. The basis for the change to the standard regarding voltage ride through starts with FERC Order

Organization	Yes or No	Question 3 Comment
		693, Paragraph 1787 (March 16, 2007), which states "... the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "Discussion, Voltage Ride-Through Although FERC Order 661-A does make a provision for future adoption of voltage ride through requirements for all generators, the Order is careful to differentiate between wind generation technologies and other, traditional generation facilities. No instruction is given for other technologies in the Order. Nowhere in any of the FERC Orders (661,661A, 693) is there a single requirement for non-wind generators to meet ride-through requirements. Docket No. RM05-4-000 (Order No. 661) discusses this subject directly. The Notice of Proposed Rulemaking (NOPR) Interconnection for Wind Energy and Other Alternative Technologies dated January 24, 2005, sought comments on certain specific issues, including whether there are other non-synchronous technologies, or other technologies in addition to wind, that should also be covered by the proposed Appendix G. In FERC Order No. 661, the Final Rule on Interconnection for Wind Energy, the Commission noted "These technical requirements for the interconnection of wind plants recognize the unique design and operating characteristics of wind plants,1 their increasing size and increasing level of penetration on some transmission systems, and the effects they have on the transmission system." Further, they wrote, "The Final Rule Appendix G we adopt here applies only to the interconnection of wind plants. The Commission does not believe at this time that the standard procedures and technical requirements in this Final Rule are appropriate for other alternative generating technologies that may supply over 20 MW at one Point of Interconnection. The standard procedures and technical requirements adopted here recognize the unique characteristics of wind plants, including the fact that they use induction generators, consist of several or numerous small generators connected to a collector system, and do not respond to grid disturbances in the same manner as

Organization	Yes or No	Question 3 Comment
		large conventional generators. ”The Final Rule also noted that while low voltage ride-through capability is needed for wind plants, it is less of a concern for large synchronous generating facilities because most of these facilities are equipped with automatic voltage control devices to increase output during low voltage events. The Commission concluded that the Final Rule Appendix G exceptions to the LGIP and1 As noted above, wind plants over 20 MW in total size are subject to the standard technical requirements in the Final Rule Appendix G. These wind plants are generally made up of several small induction wind generating turbines, laid out over a large area, and connected through a medium voltage collector system. This collectors ystem is connected to the low voltage side of the step-up transformer, which is then connected to the transmission system at a single Point of Interconnection. LGIA apply only to large wind plants. Appendix G was designed around the special needs and design characteristics of wind generators. The Appendix G provisions adopted “focuses on the special characteristics of large wind plants, particularly the fact that they utilize many induction generators connected to the transmission system at a single point through a medium-voltage collector system. The Commission has not found at this time that any other technologies, including the solar generators without fueled backup ..., have similar characteristics.” The Project 2007-09 Generator Verification Standard Drafting Team has presented the current draft of the standard as a technology-neutral version, ignoring the fact that power plant performance in asynchronous vs. synchronous units for transmission excursions are significantly different and are technology dissimilar for reasons of voltage regulation ability and plant auxiliary design. The NERC System Protection and Control Subcommittee wrote, in previous comments, “FERC 661-A is a wind generator facility ride-through performance criterion, not a synchronous generator relay setting requirement. They cannot be considered as being the same. This requirement in PRC-024 should only apply to non-synchronous machines.” Constellation Power wrote, “The idea of a ride-through curve originated with wind farms, and is not conceptually appropriate. For example, this approach is not conceptually

Organization	Yes or No	Question 3 Comment
		appropriate for cylindrical rotor synchronous machines.” PPL Energy commented, “PPL is concerned with the following concepts in the standard: 1) The standard applies equally to asynchronous and synchronous machines, salient pole and round rotor machines, photovoltaic, and other resources and as such the standard does not appear to recognize that these technologies respond differently to voltage and frequency excursions.” AEP posited “The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied.” Pacificorp offered “Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a “one-size fits all” standard applicable to all generation platforms.” Furthermore, OEM’s have not yet developed a solution to voltage ride through for non-wind generators. Assured compliance with PRC-024 may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. Regulation should not come before a solution is available. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of medium and low voltage auxiliary systems in a plant can be accurately modeled. In response to numerous questions on the feasibility of a plant design with the new voltage and frequency ride through curves, the Standard Drafting Team responded that “The implementation schedule calls for six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs.” Thus the SDT has recognized that the technology to comply does not exist today. Southern Company noted that

Organization	Yes or No	Question 3 Comment
		"We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers." Duke Energy states in their comments, "An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed." Indiana Municipal Power Agency questioned whether the technology to meet this requirement was currently available to a newly built generating facility. "To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the grid on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available?" In a previous posting of the standard, GenOn Energy suggested "It does not appear that the SDT has carefully considered the possible impact of Attachment2 on plant electrical auxiliary motors and contactors. The SDT should ask a power plant engineering company the impact on the electrical auxiliaries of an 800MW coal unit with a scrubber." If a solution is identified prior to implementation, preliminary estimates suggest the potential cost of complying with wider standards might increase machine costs as much as 25%, which is not insignificant. The result would be a considerable increase in capital and O&M costs for new (non-wind) generation due to increased equipment costs to meet more robust design specifications. The increase in costs, in combination with the compliance risk associated with not having a technical solution available at time of construction, will likely discourage new power plant construction outside of wind generation. This barrier to new construction could lead to mid-term reliability concerns, particularly in markets already stressed with tight reserve

Organization	Yes or No	Question 3 Comment
		margins. Finally, the Standard Drafting Team has not demonstrated a grid-wide reliability gap justifying the need for voltage ride through for traditional (non-wind) generators. The US Bureau of Reclamation noted "We believe there is no convincing reliability based rationale to expand the scope of the FERC Order via this standard to include synchronous machines, noting that Generators are already required (PRC-001-1) to coordinate settings with the host Transmission Operator." Both EPRI and IEEE have held discussions on this topic and have expressed concerns related to those issues noted previously. While these legitimate concerns about voltage ride through requirements for non-wind generators are being debated, they are also holding up other significant issues to be addressed by PRC-024 such as relay setting coordination and frequency ride through. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** **Additionally, Requirements R1, R2, and R3 now are applicable to all generating**

Organization	Yes or No	Question 3 Comment
		units, not only existing units. The time frame of the voltage ride thru curve of Attachment 2 has been reduced to 4 seconds. 2) Discussion, Frequency Ride-Through The risk of incurring resonant vibration of steam turbine last-stage blades is generally related to blade length, so the off-frequency ride-through criteria in Att. 1 of PRC-024-1are a concern for larger units. Nuclear plants in particular may be required to operate not only outside of OEM recommendations but at conditions that are unsafe. Please see in this respect the SERC Generation Subcommittee Nuclear Plant Review of PRC-024 Curves presentation made at the SERC Engineering Committee Meeting of March16, 2011 at Charlotte, NC. Steam turbine off-frequency limits are moreover generally subject to lifetime duration limits, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur, leaving users with ostensibly compliant equipment still at risk if major upsets take place more often than had been anticipated. Some gas turbines may experience surge or combustion upsets (including flame-out) at the off-speed conditions of Att. 1, in addition to potentially incurring blade vibration issues similar to those described above. **Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 or Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3.** 3) Additional costs associated with maintaining voltage sensitive equipment (power transformer, rotating equipment, breaker controls, etc.). Fan and pump performance will be affected at the frequency limits of Att. 1, and below rated voltage per Att. 2 may cause this equipment to stall, causing main flame trips, high/low duct pressure trips, drum level oscillations below the low water cut-out point and the like. This is especially the case if cycling above and below the rated frequency during Disturbances (but within the limits of Att. 1) magnifies system oscillations or drives automatic control systems unstable. The basis of compliance

Organization	Yes or No	Question 3 Comment
		for new units is simply, “will not trip,” i.e. covering all issues cited above plus any unpredictable other factors that may take units down. It is not realistic to expect such sweeping guarantees to be available on a system-wide basis, even if some individual pieces of equipment can ostensibly comply with Atts. 1 and 2,effectively shutting-down the new power plant industry unless an owner were willing to take unbounded risk. A “will not trip” obligation may also effectively ban entire classes of equipment, including combined cycle plants (as regards the chances of incurring lean blow-out) and (as mentioned earlier) nuclear facilities. It is noteworthy in this respect that environmental regulators have for decades been pushing gas turbine dry low-NOx combustors to the brink of instability during even steady-state operation, with inevitable negative implications for survival of Disturbances, and there were in fact many gas turbine flameout ttrips during the blackout of ‘03. Greater consideration of BES reliability may be needed, but doing so by issuing dueling regulations would not constitute an appropriate approach. That is, we believe that passage of PRC-024 in its present form would cause the available design room between environmental and NERC regulations for gas turbines to become less than zero, so merely allowing time for development of new designs is not a solution. NERC, the EPA, OEMs and industry groups need to develop a mutually acceptable set of performance requirements. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of**

Organization	Yes or No	Question 3 Comment
		transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. 4) Other Concerns M5 of PRC-024 causes new-unit tripping due to frequency or voltage excursions within the specified limits to constitute a violation, but it is unlikely that "or" events would occur. That is, Disturbances are likely to cause frequency and voltage to simultaneously deviate from the rated values, and it is unclear how this combination of factors would be addressed in assessing compliance with the stands-separate basis of Att. 1 and Att. 2 inthis standard. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the

Organization	Yes or No	Question 3 Comment
		need for a requirement in a reliability standard. 5) The grandfathering of existing units in R1 and R2 for, "documented and communicated equipment limitations," is problematical; since the propensity to incur drum level fluctuations, air/flue gas flow oscillations, flame-out and the like during Disturbances will not be defined in OEM literature, nor is it possible to predict by calculations when such problems will occur, especially if a complex Disturbance involves cycling between above and below the rated frequency (but within the Att. 1 boundaries). The same is true Page 8 of 8 regarding predicting transient fluctuations of aux bus voltages, ref. risk of contactor drop-out and stalling major auxiliary equipment. The concern above applies also to having to make reference per R3 to, "study results, experience from an actual event, or manufacturers advisory." Few if any GOs are likely to possess such documentation for Disturbances as extreme as those specified in Att. 1and Att. 2. The list of types of evidence in R3 is not exclusive; but it is difficult to imagine alternative forms of hard evidence that could be developed, other than for the comparatively few plants that possess high-fidelity dynamic simulators. **Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 or Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3. Requirements R1, R2, and R3 now are applicable to all generating units, not only existing units.** 6) The same concerns regarding availability of information apply for the, "estimate of the time duration the existing generation unit will remain connected," in R4. Relying on "sound engineering judgment" is permitted, and R4 states that "detailed unit performance studies are not required;" but the word "sound" implies that the estimate is to be based on accurate data, and such information could be developed only via a detailed study (which, as noted above, would be impossible to perform).

Organization	Yes or No	Question 3 Comment
		The methods of determination listed within R4 are provided to emphasize that detailed studies are not required. 7) The prohibition against tripping for existing units applies not just to actuation of Protection Systems but to "protective relaying," which per footnote #1 in PRC-024 includes "protective functions within control systems...based on frequency or voltage inputs." It is unclear whether or not this definition covers contactor drop-out or actuation of fan stall protection systems at extreme under-voltage conditions. Confusion is created by making grandfathering of protective relay settings, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." It is semantically unclear whether or not any grandfathering is actually being allowed. **Footnote 1 does not cover the items you have listed above. The exclusion of the relays listed is so that they alone are not allowed to be the reason that the unit is permitted to trip.** 8) The exemption take-back in the last bullet item of R3.1 (a 10% increase in nameplate capacity) again may again effectively ban entire classes of equipment, or at least prevent units from ever receiving capacity and efficiency enhancements. **If an entity replaces a piece of equipment that is causing a limitation per Requirement R3 and increases capacity by 10%, it must address the limitations. This is analogous to New Source Standards for pollution control.** 9) Conclusion & Recommendation Based on the issues discussed above, the SRT recommends against adoption of Draft4 (dated Oct. 4, 2012) of PRC-024-1. Furthermore, the SRT recommends that a deputation of NAGF members meet with the SDT for the purpose of developing a mutually-acceptable draft standard. This effort should include discussions with OEMs and industry groups regarding identifying the technical state of the art, and also with environmental regulators,

Organization	Yes or No	Question 3 Comment
		if necessary, for achieving suitable emissions vs. BES reliability balance. **The GVSDT has had many active participants throughout the life of the project representing generator owners and operators, as well as OEMs. All meetings to develop this standard have been open to all participants. The drafting team has considered each comment received on this standard during each posting and made appropriate revisions. Based on your comments and the comments of numerous other stakeholders, the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.**
Response: Thank you for your comments. Please find responses to your individual comments above.		
seattle city light		Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner should be added to the Applicability section because one or another of these are asked in R4 to provide information to the Generator Operator to

Organization	Yes or No	Question 3 Comment
		begin the evaluations.
Response: These entities were not added to the Applicability because a request for the data specified in R4 may or may not be desired by the parties. Mention of the RC and TOP have been removed from R4.		
ReliabilityFirst		ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: VSL Requirement R5 - ReliabilityFirst still believes the VSL for Requirement R5 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R5 states "Each Generator Owner shall design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion." The VSL states "The Generator Owner's generator tripped due to a Frequency Excursion within the no-trip parameters set forth in attachment 1". Based on the FERC Guideline #3, the language in the requirement is not consistent with the associated VSL. It is not a violation of Requirement R5 if the generator tripped offline within the no-trip parameters, rather it is a violation if the GO failed to design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion within the no-trip parameters set forth in Attachment 1. Furthermore the SDT noted in the response to comments that the VSL relates to Measure M5. ReliabilityFirst would like to remind the SDT that based on the NERC definition of VSL (as noted in the NERC Standard Processes Manual), "VSLs define the degree to which compliance with a Requirement was not achieved." There is no mention of VSLs being written based on the measurement of the requirement. ReliabilityFirst recommends either modifying the requirement or VSL so they both use consistent language.
Response: Based on comments from numerous stakeholders the SDT has decided to remove Requirement R5 from the next draft		

Organization	Yes or No	Question 3 Comment
of the standard. In doing this, Measure M5 and the VSL's for Requirement R5 also have been removed.		
Idaho Power Company		1) Requirement R1 and R2: Idaho Power System Planning comments that the GVSDT clarify if this standard applies to voltage or frequency elements only or if it applies to all generator protection elements as suggested in footnote 1. **Footnote 1 clarifies which protective relaying is included in the scope of R1 and R2.** 2) Requirement R5:Idaho Power System Planning comments that the GVSDT consider adding an exception to Requirement R5 that generation may trip if the Generator Owner has a documented over/under frequency limitation that cannot meet the stepped "no trip" curve shown in Attachment 1 provided that the Generator Owner and Transmission Operator have a documented mitigation plan approved by the Reliability Coordinator to trip equal load for instances of anticipated generation loss (similar to Item 13 of the WECC Off-Nominal Frequency Load Shedding Plan). **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces**

Organization	Yes or No	Question 3 Comment
		without the need for a requirement in a reliability standard. 3) Page 20: Idaho Power System Planning comments that the GVDST should clarify if Items 6a-6c are expected to be met simultaneously as it is not likely that a generator be capable of operating at full load (Pmax) and 0.95 pf lagging continuously. Idaho Power System Planning comments that the GVDST consider a 0.95 leading power factor condition in addition to the item included in Items 6a-6c. **The load point specified in Clarifications 6a-6c are provided to enable the calculation of the generator bus voltage during the periods of transmission system voltage exclusion described by the curve of Attachment 2. It is presumed to be typical of the normal operating condition of many generators. As the generator over/undervoltage relays are often connected to generator bus PTs, this calculation is necessary to determine their operating characteristic during transmission system voltage excursions. The SDT believes that this load point is adequate for determining if the voltage relays will operate during these conditions.** 4) Requirement R6 is overly burdensome with questionable impact on reliability. **This requirement is only applicable after a request has been made to the GO. The RC and TOP have been removed from this requirement as those parties have the ability to ask for this type of information through IRO-010 and/or TOP-003. The requesting entities would be using the information in stability studies. Having accurate information for these standards has a significant impact on grid reliability.** 5) Items 6a-6c on page 20 are not consistent with nor relevant to normal relay setting development practice. Initial operating points should be developed from good engineering judgment, not prescribed in this way. **The SDT believes that the use of this operating point will provide an adequate solution for determining the voltage relay response to a transmission system voltage excursion. Note that the automatic voltage regulator response has not been addressed in this calculation method. In consideration of this response,**

Organization	Yes or No	Question 3 Comment
		the load point specified will yield a conservative result.
Response: Thank you for your comments. Please find responses to your individual comments above.		
Associated Electric Cooperative, Inc. - JRO00088		Requirement R3 qualifies "each known equipment limitation". Measure M3 omits the "known" qualifier, stating the expectation of measurement is to have "any equipment limitations" documented. Is the expection for "any" to mean "some", or "all known"?
Response: Thank you for your comments. "Known" has been added to M3. The expectation is that any and all known equipment limitations be documented.		
Northeast Power Coordinating Council		1) Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings. **The requirements are written generally on a generating unit basis. For plants that are in the scope due to an aggregate of small units, those should be counted on a complete facility basis. From the total number of individual units and aggregate facilities, one can simply calculate a ratio of number completed versus total number.** 2) Regarding the Table for the Quebec Interconnection in Attachment 1, the data should read: High Frequency Duration Frequency (Hz) Time (Sec)Greater than 66.0 Instantanous Trip Greater than 63.0 5Greater than 61.5 90Greater than 60.6 660Less than or equal to 60.6 Continuous Operation Low Frequency Duration Frequency (Hz) Time (Sec)Less than 55.5

Organization	Yes or No	Question 3 Comment
		Instantaneous Trip Less than 56.5 0.35Less than 57.0 2Less than 57.5 10Less than 58.5 90Less than 59.4 660Greater than or equal to 59.4 Continuous Operation Wind generation is included in the table as has been previously confirmed with the Drafting Team. **The operator symbols found in the Quebec table for frequency/time match the note found on Attachment 1 regarding the boundary lines. The "no trip zone" does not include the lines.**
Response: Thank you for your comments. Please find responses to your individual comments above.		
Luminant		The following is a copy of a white paper that was sent to generator owners and other industry organizations on requirements R4 and R5. At the end of the paper are Luminant's recommendations for this standard. NERC Reliability Standards Project 2007-09 Generator Verification PRC-024 Generator Performance During Frequency and Voltage Excursions October 22, 2012 Introduction Project 2007-09 Generator Verification includes draft standard PRC-024, Generator Performance During Frequency and Voltage Excursions. Requirements R3 and R4 are for existing generating units. R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented cases where generator protective relaying cannot be set and directs those generators to communicate that limitation to the RC, PC, TOP and TP so its performance can be modeled correctly. R4 requires a Generator Owner to estimate the time duration for remaining on-line based on a Transmission Planner's dynamic study. Requirement R5 directs all new generating facilities to be designed, built and maintained so that they are able to ride through the excursions defined in Attachment 1 and 2. Background In FERC Order 661 (June 2, 2005), Final Rule on Interconnection for Wind Energy, the Commission adopted a low voltage ride-through standard for wind generators, but provided that a wind plant is required to meet the standard only if the Transmission Provider shows, in the System Impact Study, that low voltage ride-through capability is needed to ensure safety or reliability. The standard, if applicable, requires the wind plant to stay online for

Organization	Yes or No	Question 3 Comment
		specified time periods and at associated voltage levels where there is a disturbance on the transmission system. Several entities requested rehearing of various aspects of the low voltage ride-through requirement and standard included in the Final Rule. In FERC Order 661-A (December 12, 2005) page 2, the Commission noted "that the standard interconnection procedures and agreement were based on the needs of traditional generation facilities and that a different approach might be more appropriate for generators relying on other technologies, such as wind plants. Accordingly, the Commission granted certain clarifications, and also added a blank Appendix G to the standard Large Generation Interconnection Agreement (LGIA) for future adoption of requirements specific to other technologies." The Commission went on to adopt in Appendix G to the LGIP limited special interconnection procedures applicable to wind plants only.The basis for the change to the standard regarding voltage ride through starts with FERC Order 693, Paragraph 1787 (March 16, 2007), which states "... the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "Discussion / Reliability Impact Although FERC Order 661-A does make a provision for future adoption of voltage ride-through requirements for all generators, the Order is careful to differentiate between wind generation technologies and other, traditional generation facilities. No instruction is given for other technologies in the Order. Nowhere in any of the FERC Orders (661, 661A, 693) is there a single requirement for non-wind generators to meet ride-through requirements. Docket No. RM05-4-000 (Order No. 661) discusses this subject directly. The Notice of Proposed Rulemaking (NOPR) Interconnection for Wind Energy and Other Alternative Technologies dated January 24, 2005, sought comments on certain specific issues, including whether there are other non-synchronous technologies, or other technologies in addition to wind, that should also be covered by the proposed Appendix G.In FERC Order No. 661, the Final Rule on Interconnection for Wind Energy, the Commission noted "These technical requirements for the interconnection

Organization	Yes or No	Question 3 Comment
		of wind plants recognize the unique design and operating characteristics of wind plants, their increasing size and increasing level of penetration on some transmission systems, and the effects they have on the transmission system.” Further, they wrote, “The Final Rule Appendix G we adopt here applies only to the interconnection of wind plants. The Commission does not believe at this time that the standard procedures and technical requirements in this Final Rule are appropriate for other alternative generating technologies that may supply over 20 MW at one Point of Interconnection. The standard procedures and technical requirements adopted here recognize the unique characteristics of wind plants, including the fact that they use induction generators, consist of several or numerous small generators connected to a collector system, and do not respond to grid disturbances in the same manner as large conventional generators.” The Final Rule also noted that while low voltage ride-through capability is needed for wind plants, it is less of a concern for large synchronous generating facilities because most of these facilities are equipped with automatic voltage control devices to increase output during low voltage events. The Commission concluded that the Final Rule Appendix G exceptions to the LGIP and LGIA apply only to large wind plants. Appendix G was designed around the special needs and design characteristics of wind generators. The Appendix G provisions adopted “focuses on the special characteristics of large wind plants, particularly the fact that they utilize many induction generators connected to the transmission system at a single point through a medium-voltage collector system. The Commission has not found at this time that any other technologies, including the solar generators without fueled backup ..., have similar characteristics.” The Project 2007-09 Generator Verification Standard Drafting Team has presented the current draft of the standard as a technology-neutral version, ignoring the fact that power plant performance in asynchronous vs. synchronous units for transmission excursions are significantly different and are technology dissimilar for reasons of voltage regulation ability and plant auxiliary design. o The NERC System Protection and Control Subcommittee wrote, in previous comments, “FERC 661-A is a wind generator facility ride-through performance criterion, not a synchronous generator

Organization	Yes or No	Question 3 Comment
		relay setting requirement. They cannot be considered as being the same. This requirement in PRC-024 should only apply to non-synchronous machines.” o Constellation Power wrote, “The idea of a ride-through curve originated with wind farms, and is not conceptually appropriate. For example, this approach is not conceptually appropriate for cylindrical rotor synchronous machines.” o PPL Energy commented, “PPL is concerned with the following concepts in the standard: 1) The standard applies equally to asynchronous and synchronous machines, salient pole and round rotor machines, photovoltaic, and other resources and as such the standard does not appear to recognize that these technologies respond differently to voltage and frequency excursions.” o AEP posited “The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied.” o Pacificorp offered “Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a “one-size fits all” standard applicable to all generation platforms.” Furthermore, OEM’s have not yet developed a solution to voltage ride through for non-wind generators. Assured compliance with PRC-024 may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. Regulation should not come before a solution is available. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of medium and low voltage auxiliary systems in a plant can be accurately modeled. o In response to numerous questions on the feasibility of a plant design with the new voltage and frequency ride through curves, the Standard Drafting Team responded that “The implementation schedule calls for

Organization	Yes or No	Question 3 Comment
		six years beyond approval of the standard before Requirement R5 goes into effect. The SDT believes this is enough time to develop the required designs." Thus the SDT has recognized that the technology to comply does not exist today. o Southern Company noted that "We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers." o Duke Energy states in their comments, "An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed." o Indiana Municipal Power Agency questioned whether the technology to meet this requirement was currently available to a newly built generating facility. "To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the grid on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available?" o In a previous posting of the standard, GenOn Energy suggested "It does not appear that the SDT has carefully considered the possible impact of Attachment 2 on plant electrical auxiliary motors and contactors. The SDT should ask a power plant engineering company the impact on the electrical auxiliaries of an 800MW coal unit with a scrubber." If a solution is identified prior to implementation, preliminary estimates suggest the potential cost of complying with wider standards might increase machine costs as much as 25%, which is not insignificant. The result would be a considerable increase in capital and O&M costs for new (non-wind) generation due to increased equipment costs to meet more robust design specifications. The increase in costs, in combination with the compliance risk associated with not having a technical solution available at time of construction, will likely discourage new power plant construction outside of wind

Organization	Yes or No	Question 3 Comment
		generation. This barrier to new construction could lead to mid-term reliability concerns, particularly in markets already stressed with tight reserve margins. Finally, the Standard Drafting Team has not demonstrated a grid-wide reliability gap justifying the need for voltage ride through for traditional (non-wind) generators. o The US Bureau of Reclamation noted “We believe there is no convincing reliability based rationale to expand the scope of the FERC Order via this standard to include synchronous machines, noting that Generators are already required (PRC-001-1) to coordinate settings with the host Transmission Operator.” Both EPRI and IEEE have held discussions on this topic and have expressed concerns related to those issues noted previously. While these legitimate concerns about voltage ride through requirements for non-wind generators are being debated, they are also holding up other significant issues to be addressed by PRC-024 such as relay setting coordination and frequency ride through. Summary and Conclusion The Standard Drafting Team should remove Requirements R4 and R5 from the current version of PRC-024 to facilitate passage of the more critical elements of the standard such as voltage and frequency relay setting requirements. The current technology neutral draft standard PRC-024 is inconsistent with the intent of FERC Order 661 -A in that it applies “equal” requirements to all generators, rather than requirements solely for wind generators which is the focus of the FERC Order. The Standard must recognize that wind generators and traditional generation facilities are technologically dissimilar and, therefore, cannot be treated the same in this instance. With no technology currently commercially available to provide guaranteed voltage ride through capabilities for traditional generation, the standard should not require this (unavailable) technology be in place in order to meet the requirements of the standard. When the technology becomes available, a new SAR may be drafted to address the voltage performance aspects of non-wind generators if an identified reliability gap exists. The new Cost Effective Analysis Process can be used at that time to evaluate the costs and benefits associated with the new requirement, as well as facilitate consideration of alternative methods to achieve the reliability objective which may result in less implementation costs and resource expenditures.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.		
TransAlta Centralia Generation LLC		The UFLS curves for Eastern Interconnection and Quebec Interconnection are different from those curves on NPCC Directory 12. Which one to be compliant?
Response: The SDT thanks you for your comment. The curve for the Eastern Interconnection coordinates with the requirements for UFLS system design documented in PRC-006-1. If the generator frequency protection is set in accordance with Attachment 1 of PRC-024, it should coordinate with the local UFLS program. The Quebec Interconnection does have unique requirements the information for Quebec was provided by Hydro Quebec and is also found in PRC-006-1.		
PSEG		1) This FIRST comment was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1.1.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1, R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all “modelers,” the result will be outdated data in someone’s model, which can have a bad result. The team should have one broad

Organization	Yes or No	Question 3 Comment
		"data sharing" policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: "The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it." **The information discussed in PRC-024 of potential interest to planners (generator voltage and frequency protection system settings) is not necessarily included in all models. The SDT feels the current wording is adequate to allow those planners who need the information to obtain it from the Generator Owners. Note that the SDT has removed the RC and TOP from data reporting requirements described in Requirements R4 and R5 (previously R6). This was done in response to stakeholders who pointed out that these functional entities can request this information via standards IRO-010 (RC) and TOP-003 (TOP).** 2) We do NOT believe that R5, which sets requirements for new generators (including balance-of-plant equipment) to the requirements in Attachment 1 and Attachment 2, has been appropriately vetted by the SDT. Many stakeholders are unfamiliar with the performance capability of new generators, including the cost of achieving the performance requirements in R5. Therefore, the SDT should develop additional expert information to confirm that the requirements in R5 represent the norm for new generation. We suggest that the SDT reach out to the NERC Planning Committee, who in turn may research this topic with the IEEE and the North American Generator Forum and develop a report on their findings. With all due respect to the SDT, until stakeholders have independent confirmation regarding R5, it will be difficult for them to accept it. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build,**

Organization	Yes or No	Question 3 Comment
		operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.
Response: The SDT thanks you for your comment. See answers to your specific questions above.		
Dynegy		This Standard is similar to the PRC-006-NPCC-1 and PRC-006-SERC-01 Automatic Underfrequency Load Shedding Standards. PRC-024-1 requires continuous operation at >59.5 Hz. PRC-006-NPCC-1 requires continuous operation at >59.0 Hz. This is confusing. These three Standards should be coordinated or the GO applicability should be removed from PRC-006-NPCC-1 and PRC-006-SERC-01.
Response: The SDT thanks you for your comment. Regional standards may be more stringent than the continent-wide NERC standards. PRC-024-1 is the controlling document in regions that do not have an equivalent regional standard.		
Utility Services		Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. The percentage numbers refer to the number of applicable generating facilities (units or aggregate plants). This is the default interpretation in lieu of any other description in the standard.		
Manitoba Hydro		1) VSLs - The VSLs for R1, R2 and R5 have been omitted for both Low, Moderate and High. Is there any rationale for this omission? **Compliance with R1 and R2 is binary (i.e., the relays are either set to ride through the defined excursion or they are not). NERC requires binary compliance requirements to be assigned to the Severe level only.** 2) Attachment 1 - Attachment 1 in MOD-026 and MOD-027 assist in adding clarity to the periodicity of exciter and turbine/governor model testing. These attachments also allow low capacity factor units and equivalent units connected at the same location to not be tested every 10 years, which is prudent. Manitoba Hydro would like the drafting team to consider whether conditions in row numbers 1-5 and 7 in attachment 1 of MOD-026 could also be applied to standards PRC-019, MOD-025 and possibly PRC-024. **The SDT does not believe the cited attachments in MOD-026 and MOD-027 apply to PRC-024.** 3) R1 and R2 - The requirement speaks about the 'unit' tripping but the sub requirements speak about the 'Generation' tripping - is this not inconsistent? **The SDT agrees and has made the wording consistently use "generating unit(s)".** 4) R1 and R2 -1. The language in R2 currently reads, "Each Generator Owner that has generator voltage protective relaying activated to trip its generating unit shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2 or within the voltage recovery characteristics of a location-specific Transmission Planner's study if the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2 subject to the following exceptions". Manitoba Hydro made the following comment to draft 3 of PRC-024-1 during /29/12-03/29/12 commenting period, "R1 - the facility

Organization	Yes or No	Question 3 Comment
		interconnection document required through FAC-001 should supersede Attachment 1 in order to best address local area issues. R1 should be revised to specify this." The drafting team responded, "The SDT was charged with creating continent-wide requirements for frequency and voltage excursions and believes that consistency will not occur if various Transmission Service Providers apply various "no trip zones." Requirement R1, therefore, should not be dictated by FAC-001." Even though the drafting stated that other standards (eg. FAC-001) shouldn't set continent wide settings, the drafting team has permitted less stringent voltage relay settings in R2 as long as it is accompanied by a Transmission Planning study. Manitoba Hydro understands that continent wide-standards are preferred but there should be flexibility for local area considerations as has been done in R2. Manitoba Hydro requests the drafting team consider the following language added to R1: ...or within the frequency recovery characteristics of a location-specific Transmission Planner's study if the Transmission Planner allows different (more or less stringent) frequency relay settings than those required to meet PRC-024 Attachment 1...And the following modification to R2:...or within the voltage recovery characteristics of a location-specific Transmission Planner's study if the Transmission Planner allows different (more or less stringent) voltage relay settings than those required to meet PRC-024 Attachment 2... **The SDT does not see where frequency recovery characteristics apply as long as the frequency remains within the envelope required by the UFLS standard (PRC-006-1). The NERC standard does not preclude more stringent voltage recovery profiles from being used under the requirements of a LGIA or regional standard.** 5) The drafting team has removed the following exception in R1, "A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec." What is the technical basis for removing this exception? Is the intent that no tripping in the "no trip zone" is permitted regardless of the potential rate of change of frequency? There were no comments on this item in the last draft. **There have been comments about the rate of change of frequency caveat in the past. The SDT was challenged by FERC to justify the value of 2.5**

Organization	Yes or No	Question 3 Comment
		Hz/sec. While this is a default value for Aurora scenario protective devices, the SDT could not provide any other justification for this value and felt obligated to remove it. The SDT would appreciate any assistance from Manitoba Hydro to justify the 2.5 Hz/sec (or any other number MH can support). 6) R2 - The first bullet has a typo - 'tripping' should be changed to 'trip'. **The redline version that was posted did have this error but the clean version (that the SDT uses) indicates the change was already made. No change required.** 7) R3 - This requirement requires that Generator Owners document each 'known' equipment limitation. The word 'known' can be legally ambiguous - known to whom? actual knowledge or 'should have known', 'could have known'? **The intent is that the Generator Owner can set protection to operate inside the "No Trip Zone" for limitations he is aware of (i.e., "known" limitations). He would not be able to do this for limitations he is not aware of (unknown limitations). The SDT believes that the most common use of this allowance is for older steam turbines that have limited low frequency operating capability as defined by the equipment manufacturer.** 8) R5 - The text of footnote 5 has been deleted, but the footnote remains. **This is an artifact of the redline function. If you look at the clean version you will see that this has been addressed.** 9) General Comments: 1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability? **The SDT believes the phased implementation plan allows Generator Owners to implement any changes in protection system settings during normally scheduled unit outages.** 10) 2. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled "Consideration for early Compliance" with language pertaining to previous testing and model verification which were completed under the applicable

Organization	Yes or No	Question 3 Comment
		regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1). **There are no verification tests involved with PRC-024-1, so the cited section does not apply to this standard.**
Response: The SDT thanks you for your comment. See answers to your specific questions above.		
SMUD		1) We much prefer a performance based, RBS approach using the internal controls process than the approach taken by the SDT. We would prefer to evaluate post event trips for compliance with the settings rather than keep extensive, zero-defect compliance documentation for all unit settings. (Intentional Space).... **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.** 2) Specific Comments: It appears that R1 & R2 are meant to be “document the settings” requirements since they refer to the Long-term Planning Time Horizon and

Organization	Yes or No	Question 3 Comment
		M1 & M2 ask for settings documentation. The requirements themselves suggest that compliance is evaluated based on actual events, though. For instance, the first bullet in R1 mentions “..impending or actual loss of synchronism..” which would not be evaluated in the Long-term Planning Time Horizon. R2 states “...such that the voltage protective relaying does not trip...” which again implies evaluating the results of an actual event. R1 & R2 are not clearly pre-event documentation only or post event analysis only - they currently try to have it both ways. Please correct this.(Intentional Space).... **Requirements R1 and R2 are not simply to document settings, but rather to ensure the protection is set so that it does not operate to trip the generator for voltage and frequency excursions that remain within the no-trip zones described in Attachments 1 and 2.** 3) We agree with the compliance approach used in R5 and encourage the SDT to use this same approach for requirements R1 & R2 **The SDT believes the compliance approach used in Requirements R1 and R2 is adequate. Requirement R5 has been removed (see response to next comment).** 4) SMUD recommends the following changes the the 5th bullet of R5: (Intentional Space)....”Generation may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation. If a legitimate equipment limitation is identified following a plant trip caused by a frequency or voltage excursion, the Reliability Coordinator shall grant a retroactive exemption for the identified limitation.” (Intentional Space)....The stuck language lends itself to arbitrary determinations and, where no fix is possible, automatically forces a non-compliance situation for an unknown condition.(Intentional Space).... **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental**

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		gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard. 6) We disagree with R6. First, the GO must provide the generator protection trip settings - this phrasing is not limited to voltage or frequency trip points, but ALL trip settings. This is unreasonable. Second, the GO should not be subjected to an indefinite requirement to constantly update an entity that sends a single written request. By the requirements in this standard, the various Coordinators and Planners know that the plant's trip settings must follow the curves. Why isn't this enough? If the Coordinators or Planners want specific setting data, they should be required to ask for it each time. Otherwise, they should model the plant as meeting the curves contained in this standard. **Based on comments from other stakeholders, the SDT has removed two of the possible requestors from Requirement R6. The SDT would like to point out that the planners that design UFLS systems require the frequency trip setting information and that PRC-006 specifically links to this reporting requirement in PRC-024. The SDT does not believe having to report other protection settings information imposes an undue burden on the Generator Owner if so requested.**
Response: The SDT thanks you for your comment. See answers to your specific questions above.		
Western Electricity Coordinating Council		WECC is concerned that Requirement R3 of PRC-024-1, which requires Generator Owners to document each known equipment limitation that prevents a generating unit from meeting the frequency requirements of Requirement R1 may be in conflict

Organization	Yes or No	Question 3 Comment
		with or less stringent than the requirement in the WECC Off-Nominal Frequency Load Shedding Plan that requires Generator Owners that have generators that do not meet the frequency requirements to automatically trip load to match the anticipated generation loss or have contractual relationships providing for automatic load shedding. The concern is that Generator Owners may interpret Requirement R3 of PRC-024 to relieve them of their obligations under the WECC Coordinated Off-Nominal Load Shedding Plan. This is a concern because the original design and subsequent simulations conducted to validate the effectiveness of the WECC Off-Nominal Frequency Load Shedding Plan reflect simulation of the generator underfrequency and overfrequency operation requirements, and any deviations from these requirements would invalidate the effectiveness studies and could potentially require modifications to the existing approved WECC Coordinated Plan.
Response: The SDT thanks you for your comment. Regional Entities are able to implement requirements via regional standards that are more stringent than the continent-wide NERC standards. PRC-024-1 does not preclude WECC from setting the requirement described. The SDT does wonder how a generator can selectively trip load that matches a dynamically changing generation output.		
Xcel Energy		1) Xcel Energy would like to point out that the high frequency duration curves for the Eastern, ERCOT, and Quebec Interconnections exceed the allowable short-term frequencies specified in IEEE C50.13 and IEC 60034 which the OEM's use to design their generators. Attachment 1 should be modified to meet the IEEE and IEC standards. **The high frequency curve for the Eastern and ERCOT Interconnections in Attachment 1 have been revised to meet the cited IEEE and IEC standards. Quebec has a unique situation and their generators are hydro-electric units that are able to meet their high frequency requirements.** 2) Also, Xcel Energy continues to believe that Requirement R5 would result in a large cost increase in the cost of building new generating units which would defer resources that could be better used elsewhere to improve grid reliability. Xcel recommends that this requirement be revised such that if a generating unit did trip

Organization	Yes or No	Question 3 Comment
		during a voltage or frequency excursion, the Generator Owner investigate the cause and develop a corrective action plan to address the trip. **Based on comments from you and numerous other stakeholders the SDT has decided to remove Requirement R5 from the next draft of the standard. The SDT believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. From a low voltage ride-through perspective, the occurrence of severe transmission system faults in the immediate vicinity of a generation facility is rare and the history of transmission faults causing trips of generating facilities is similarly rare. From a frequency excursion perspective, turbines and generators currently on the market easily meet the requirements for coordinating with UFLS programs when challenged with typical frequency excursions. While there have been issues with frequency oscillations in some cases (e.g., lean fuel blowout), the SDT believes that these types of issues can be resolved by market forces without the need for a requirement in a reliability standard.**
Response: The SDT thanks you for your comment. See answers to your specific questions above.		
Northeast Utilities		No comment

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
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Proposed Action Plan and Description of Current Draft:

This is the fifth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This fifth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop fifth version draft standard.	December 2012
2. Post response to comments and conduct successive ballot.	December 2012
3. Develop responses to ballot comments.	January 2013
4. Post responses to comments and conduct recirculation ballot.	January 2013

5. BOT adoption.	February 2013
6. File with regulatory authorities.	March 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Performance During Frequency and Voltage Excursions

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure generating units remain connected during frequency and voltage excursions and ensure expected generating unit performance during frequency and voltage excursions is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

   5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

   5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

   5.2. In those jurisdictions where regulatory approval is not required:

   5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its generating unit(s) shall set such protective relaying so that the frequency protective relaying does not operate to trip the generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting the generating unit.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection[2]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2 or within the voltage recovery characteristics of a location-specific Transmission Planner's study if the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2 subject to the following exceptions : *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known equipment limitation[3] that prevents a generating unit from meeting the criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

3.1. The Generator Owner shall communicate the documented equipment limitation, or the removal of a previously documented equipment limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of any of the following:

- Identification of an equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Modification or upgrade of the equipment causing the limitation that results in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).

R4. Within 60 calendar days of receipt of a written request from a Planning Coordinator or Transmission Planner, each Generator Owner shall provide an estimate of the time duration which the generating unit(s) will remain connected (including the performance of the auxiliary systems) if the unit(s) were to experience a frequency or voltage excursion. The voltage or frequency profile at the point of interconnection is provided by a Planning Coordinator or Transmission Planner that models the associated generating unit(s) and which has requested the time duration estimate.

If the Generator Owner expects the generating unit(s) will remain connected for the duration of the profile of the excursion provided, the estimate should indicate the generating unit(s) is not expected to trip. The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment. Detailed generating unit(s) performance studies are not required to develop the estimate. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

[3] Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.

R5. Each Generator Owner shall provide its generator protection trip settings to the Planning Coordinator or Transmission Planner (that models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless otherwise directed by the requesting Planning Coordinator or Transmission Planner. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets, or other documentation.

M2. Each Generator Owner shall have that generator voltage protective relays have been set in accordance with Requirement R2 evidence such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known equipment limitations (excluding limitations that are caused by generator frequency and voltage protective relays) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

M4. Each Generator Owner shall have evidence that an estimate of the time duration of its existing generating unit(s) as a result of a frequency excursion or voltage excursion has been communicated in accordance with Requirement R4, such as a copy of the estimate of time duration report and correspondence, such as dated e-mails, or other documentation and copies of any requests it has received for that information.

M5. Each Generator Owner shall have evidence that it communicated generator protective relay settings to a requesting entity within 60 calendar days of a request or change in setting(s) in accordance with Requirement R5, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information..

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R5, Measures M1 through M5; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit has no documented and communicated equipment limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit has no documented and communicated equipment limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 30 calendar days but less than or equal to 40 calendar days of identifying the limitation.	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 40 calendar days but less than or equal to 50 calendar days of identifying the limitation.	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 50 calendar days but less than or equal to 60 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 60 calendar days of identifying the limitation.
R4	The Generator Owner provided an estimate of a unit's performance more than 60 calendar days but less than or equal to 70 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 70 calendar days but less than or equal to 80 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 80 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner failed to provide an estimate of a unit's performance within 90 calendar days of a written request. .
R5	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 70 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60	The Generator Owner provided its generator protection trip settings more than 70 calendar days but less than or equal to 80 calendar days of any change to those trip settings. OR	The Generator Owner provided its generator protection trip settings more than 80 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR	The Generator Owner failed to provide its generator protection trip settings within 90 calendar days of any change to those trip settings. OR The Generator Owner failed to

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar days but less than or equal to 70 calendar days of a written request.	The Generator Owner provided trip settings more than 70 calendar days but less than or equal to 80 calendar days of a written request.	The Generator Owner provided trip settings more than 80 calendar days but less than or equal to 90 calendar days of a written request.	provide trip settings within 90 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

Version History

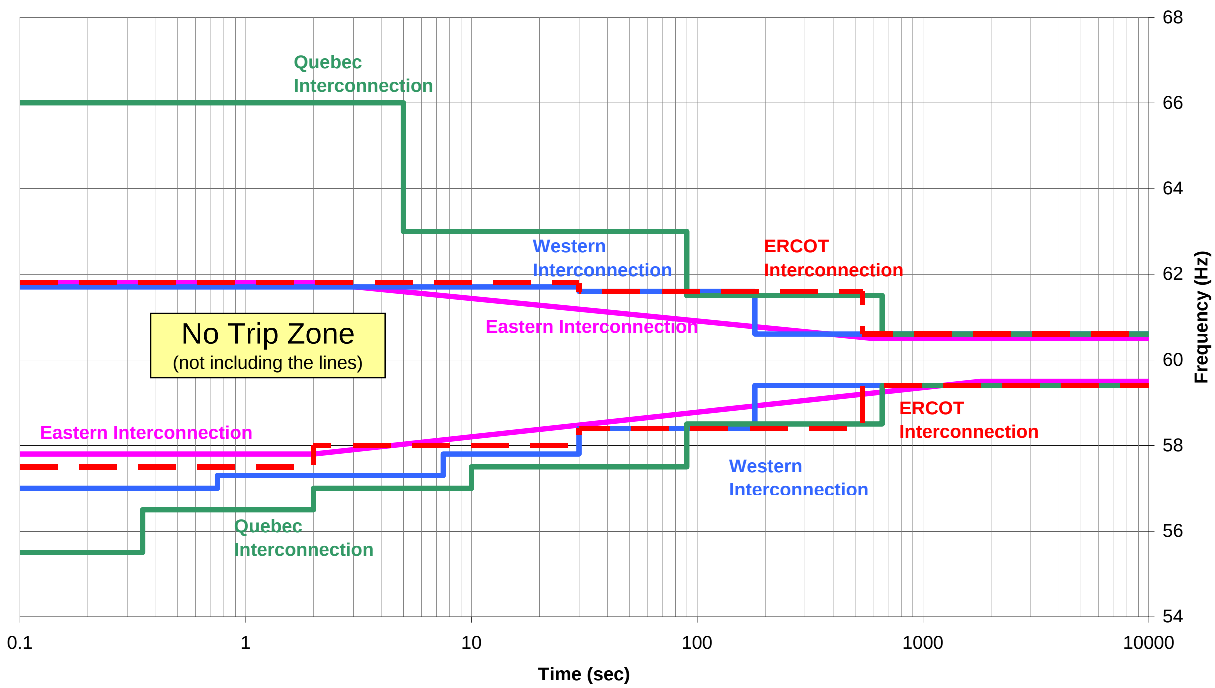
Version	Date	Action	Change Tracking

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(118.0602-1.9055*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

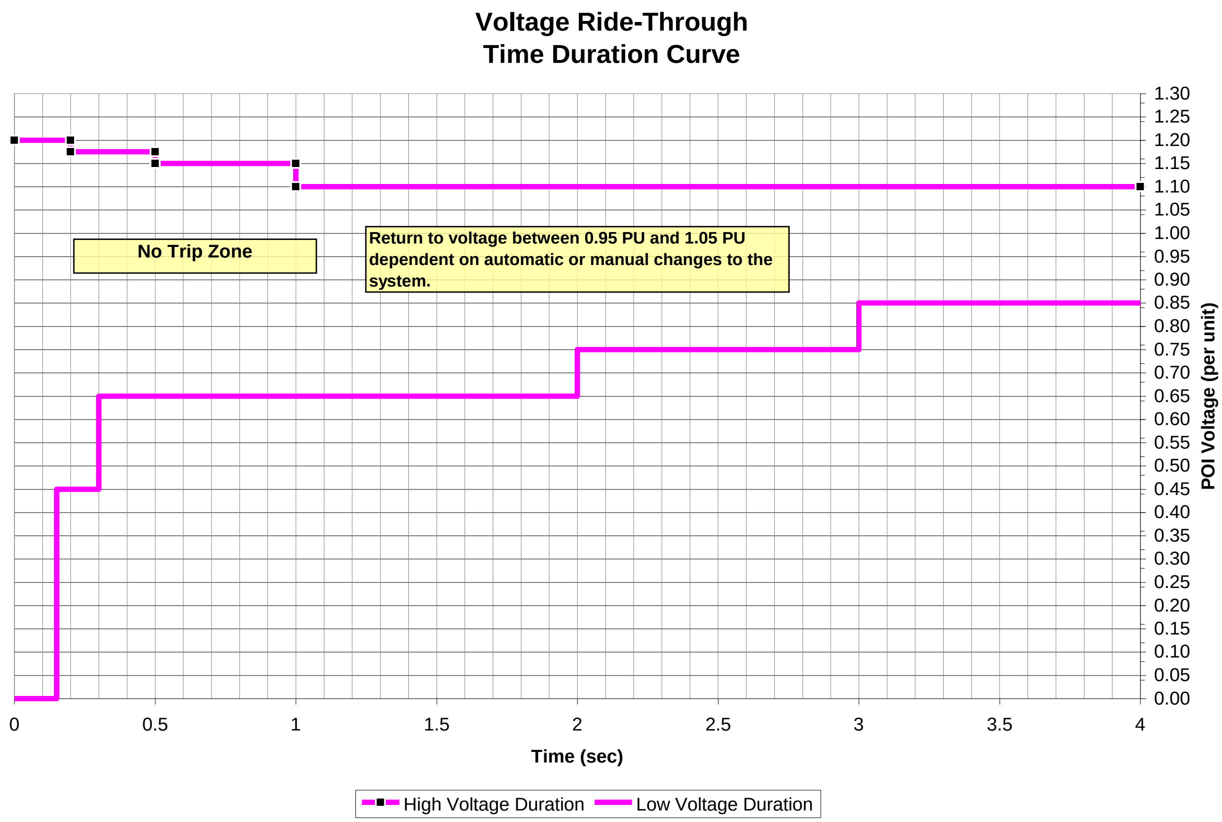
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Curve Data Points:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	0.00	0.15
≥1.175	0.20	<0.45	0.30
≥1.15	0.50	<0.65	2.00
≥1.10	1.00	<0.75	3.00
>1.05	600	<0.90	600
≤1.05	Continuous operation	≥0.95	Continuous operation

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use the following assumptions to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating,
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals).
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Roadmap

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Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
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Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop ~~third~~ fifth version draft standard.	December ~~April – July~~ 2012
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3. Develop responses to ballot comments.	~~December 2012 –~~ January 2013

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6. File with regulatory authorities.	~~April~~March 2013

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2. **Number:** **PRC-024-1**

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4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

   5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

   5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and ~~R6~~R5.

~~**5.1.5** By the first day of the first calendar quarter, six calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirement R5.~~

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

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R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its generating unit(s) shall set such protective relaying so that the frequency protective relaying does not operate to trip the generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) ~~on~~ may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.
- Generating unit(s) ~~on~~ may trip if clearing a system fault necessitates disconnecting the generating unit~~on~~.
- Generating unit(s) ~~on~~ may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated equipment limitations in accordance with Requirement R3 ~~for an existing generating unit[2]~~.

R2. Each Generator Owner that has generator voltage protective relaying[1]~~[1]~~ activated to trip its generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection[3]) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2 or within the voltage recovery characteristics of a location-specific Transmission Planner’s study if the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2 subject to the following exceptions : *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~Generation~~Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).

---

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, ~~impedance relays, voltage controlled overcurrent relays,~~ multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

~~[2] To include generating units previously commissioned, or generating units under construction, or generating units with an executed interconnection agreement or power purchase agreement by the effective date of PRC-024-1 Requirement R5.~~

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- ~~Generation~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- ~~Generation~~Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- ~~Generation~~Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated equipment limitations in accordance with Requirement R3~~ for an existing generating unit~~.

R3. Each Generator Owner ~~of an existing generating unit~~ shall document each known equipment limitation[4] ~~(excluding limitations that are caused by generator frequency and voltage protective relays)~~ that prevents a generating unit~~,~~ from meeting the criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

3.1. The Generator Owner shall communicate the documented equipment limitation, or the removal of a previously documented equipment limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of any of the following ~~identifying the equipment limitation or when either of the following occurs~~:

- Identification of an equipment limitation.
- Repair of ~~T~~the equipment causing the limitation that removes the limitation.
- ~~is repaired or replaced~~ Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Modification or upgrade of ~~T~~the equipment causing the limitation ~~is modified or upgraded~~ that results~~ing~~ in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).

R4. Within 60 calendar days of receipt of a written request from a Planning Coordinator or Transmission Planner, e~~E~~ach Generator Owner ~~of an existing generating unit~~ shall provide an estimate of the time duration which the~~ existing~~ generating unit(s) will remain connected (~~consider~~including the performance of the auxiliary systems~~ as well as the generator~~) if the unit(s) were to experience a frequency or voltage excursion. The voltage or frequency profile at the point of interconnection is ~~determined by dynamic simulation~~ provided by a ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator~~ or

[4] Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.

Transmission Planner that ~~monitors or~~ models the associated generating unit(s) and which has requested the time duration estimate. ~~The estimate is to be provided to the requesting Reliability Coordinator, Planning Coordinator, Transmission Owner, or Transmission Planner within 60 calendar days of receipt of a written request.~~

If the Generator Owner expects the ~~existing~~ generating unit(s) will remain connected for the duration of the profile of the excursion provided~~longer than 10 minutes~~, the estimate should indicate the generating~~existing~~ unit(s) is not expected to trip. The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment. Detailed generating unit(s) performance studies are not required to develop the estimate. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~**R5.** Each Generator Owner shall design, build, and maintain new[5] generating units and plants (including auxiliary systems) consistent with the parameters set forth in PRC-024 Attachments 1 and 2, such that the generation, when operating at or above the minimum sustainable generation threshold (and for a generating plant consisting of multiple units with total generation greater than 75 MVA gross aggregate nameplate rating, when the generating plant is producing at least 20 percent of the plant's aggregate nameplate capacity) will not trip due to a frequency excursion or voltage excursion at the point of interconnection, caused by an event on the transmission system external to the generating plant, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*~~

- ~~For a new generating plant consisting of multiple units less than 20 MVA each with total plant generation greater than 75 MVA (gross aggregate nameplate rating), up to 10 percent of the individual generating units may disconnect as a result of the frequency or voltage excursion.~~
- ~~If the Transmission Planner has provided the Generator Owner with location-specific voltage recovery characteristics as described in Requirement R2, Part 2.2, then the generation may operate to a less stringent voltage ride-through performance criterion than the duration curve identified in PRC-024 Attachment 2 consistent with those provided characteristics.~~
- ~~Generation may trip if this action is designed as part of a Special Protection System (SPS) or Remedial Action Scheme (RAS).~~
- ~~Generation may trip if clearing a system fault necessitates disconnecting the generation.~~

[5] ~~Excluding generators referenced in PRC-024-1 Footnote 2.~~

- ~~Generation may trip if the Generator Owner has a temporary exemption granted by its Reliability Coordinator based on a documented equipment limitation. If an equipment limitation is identified following a plant trip caused by a frequency or voltage excursion, the Reliability Coordinator may grant a retroactive temporary exemption for that limitation if the Generator Owner develops and implements an acceptable plan to address the limitation.~~
- ~~Generation may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~

~~R6.~~R5. Each Generator Owner shall provide its generator protection trip settings to the ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator~~ or ~~and~~ Transmission Planner (that ~~monitors or~~ models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless otherwise directed by the requesting ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator,~~ or Transmission Planner. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets, or other documentation~~, that generator frequency protective relays have been set in accordance with Requirement R1~~.

M2. Each Generator Owner shall have that generator voltage protective relays have been set in accordance with Requirement R2 evidence such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies~~, that generator voltage protective relays have been set in accordance with Requirement R2~~.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known equipment limitations (excluding limitations that are caused by generator frequency and voltage protective relays) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

M4. Each Generator Owner shall have evidence ~~such as a copy of the estimate of time duration report and correspondence, such as dated e-mails, or other documentation~~ that an estimate of the time duration of its existing generating unit(s) as a result of a frequency excursion or voltage excursion has been communicated in accordance with Requirement

R4, such as a copy of the estimate of time duration report and correspondence, such as dated e-mails, or other documentation and copies of any requests it has received for that information.

~~**M5.** Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied.~~

~~**M6.**~~**M5.** Each Generator Owner shall have evidence ~~such as dated e-mails, correspondence or other evidence~~ that it communicated generator protective relay settings to a requesting entity within 60 calendar days of a request or change in setting(s) in accordance with Requirement R5~~6~~, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information..

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance E~~e~~nforcement A~~a~~uthority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional E~~e~~ntity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R5~~6~~, Measures M1 through M5~~6~~; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit has no documented and communicated equipment limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit has no documented and communicated equipment limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 30 calendar days but less than or equal to 40 calendar days of identifying the limitation.	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 40 calendar days but less than or equal to 50 calendar days of identifying the limitation.	communicated the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner more than 50 calendar days but less than or equal to 60 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 60 calendar days of identifying the limitation.
R4	The Generator Owner provided an estimate of a unit's performance more than 60 calendar days but less than or equal to 70 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 70 calendar days but less than or equal to 80 calendar days of a written request.	The Generator Owner provided an estimate of a unit's performance more than 80 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner failed to provide an estimate of a unit's performance within 90 calendar days of a written request. .
~~**R5**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Generator Owner's generator tripped due to a frequency excursion within the no-trip parameters set forth in Attachment 1 and did not meet any of the exceptions specified in the bulleted list within Requirement R5.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~OR~~ ~~The Generator Owner's generator tripped due to a voltage excursion within the no-trip parameters set forth in Attachment 2 and did not meet any of the exceptions specified in the bulleted list within Requirement R5.~~
R5~~6~~	The Generator Owner provided its generator protection trip settings ~~as specified by Requirement R6~~ more than 60 calendar days but less than or equal to 70 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 70 calendar days of a written request.	The Generator Owner provided its generator protection trip settings ~~as specified by Requirement R6~~ more than 70 calendar days but less than or equal to 80 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 70 calendar days but less than or equal to 80 calendar days of a written request.	The Generator Owner provided its generator protection trip settings ~~as specified by Requirement R6~~ more than 80 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 80 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings ~~as specified by Requirement R6~~ within 90 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 90 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

Version History

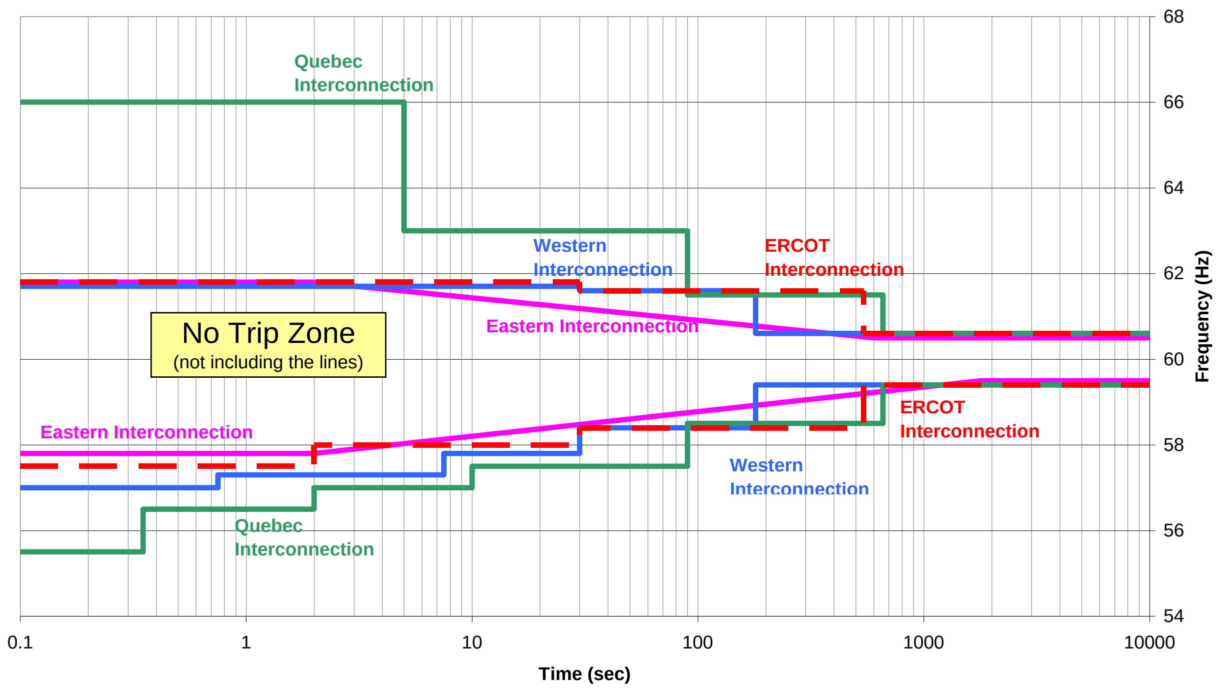
Version	Date	Action	Change Tracking

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8~~2.2~~	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(118.0602-1.9055*f)}$ ~~$10^{(91.1132-1.46*f)}$~~	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

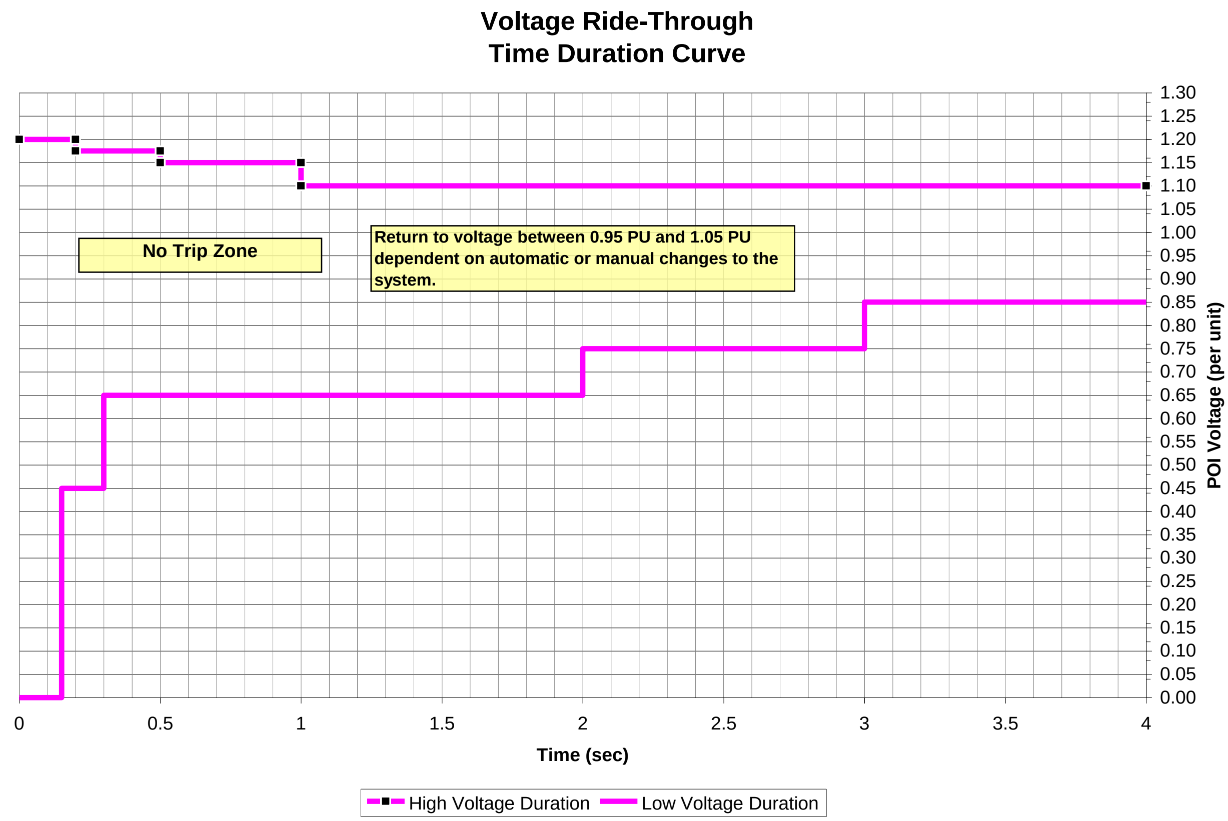
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8~~2.5~~	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6~~≥62.0~~	30~~2~~	≤58.0	2
≥60.6~~≥61.6~~	540~~30~~	≤58.4	30
<60.6~~≥60.6~~	Continuous operation~~540~~	≤59.4	540
~~<60.6~~	~~Continuous operation~~	>59.4	Continuous operation

PRC-024— Attachment 2



Curve Data Points:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	0.00	0.15
≥1.175	0.20	<0.45	0.30
≥1.15	0.50	<0.65	2.00
≥1.10	1.00	<0.75	3.00
>1.05	600	<0.90	600
≤1.05	Continuous operation	≥0.95	Continuous operation

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. Adjust the magnitude of the high voltage curve in proportion to deviations of frequency below normal.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use the following assumptions to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating,
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals).
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Performance During Frequency and Voltage Excursions

Approvals Required

PRC-024-1 – Generator Performance During Frequency and Voltage Excursions.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to

such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, R4, and R5 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Performance During Frequency and Voltage Excursions

Approvals Required

PRC-024-1 – Generator Performance During Frequency and Voltage Excursions.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to

such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- ~~By the first day of the first calendar quarter, six calendar years following applicable regulatory approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirement R5~~.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, R4, and R5~~6~~.

- ~~By the first day of the first quarter, six calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirement R5.~~

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, R4, and R5~~6~~ involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

~~Requirement R5 involves the performance of complete generation facilities (i.e. the prime mover, its fuel supply, and all auxiliary systems). To date, most Generator Owners have not specified this type of performance and the engineering companies designing generating facilities have not designed the facilities to ride through frequency and voltage excursions of the severity specified in PRC-024. In order to allow Generator Owners and architect/engineering companies time to develop new designs to meet R5, the SDT allows six years from regulatory approval for implementation.~~

Project 2007-09 Generator Verification PRC-024-1 Generator Performance During Frequency and Voltage Excursions

Unofficial Comment Form

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to PRC-024-1. Comments must be submitted by by 8 p.m. ET **January 11, 2013**. If you have questions please contact Stephen Crutchfield at stephen.crutchfield@nerc.net or by telephone at [609-651-9455].

Background Information

The Generator Verification Standard Drafting Team posted PRC-024-1 - Generator Performance During Frequency and Voltage Excursions, from September 28 through October 31, 2012 for a 30-day concurrent comment/successive ballot period. The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

The GVSDT also previously revised R4 to improve clarity. A majority of the stakeholders agreed that the revision had improved clarity. Some stakeholders were still unclear if the activities described in this requirement were to be performed by request only, so the SDT rearranged the sentences to clarify that the activities were to be performed upon request. Some stakeholders pointed out the RCs and TOPs can request such information via requirements in other standards (IRO-010-1a and TOP-003-2), so these two functional entities were removed from this requirement, as well as R6.

Based on comments from a majority of stakeholders, Requirement R5 (along with its associated Measure M5 and VSL's) was removed from the Standard. The SDT believes that Requirement R4 achieves the reliability objective of Paragraph 1787 of FERC Order 693 that Requirement R5 was written to address. Other changes were made in response to comments from several stakeholders including:

- Additional wording in the Effective Date section for jurisdictions where regulatory approval is required to address the situation in some Canadian provinces.
- A modification to the high frequency allowable trip point in Attachment 1 for the Eastern and ERCOT Interconnections to match IEEE and IEC standards for generator manufacturers.

- A modification to the final voltage value of the low voltage curve and time duration of Attachment 2 to coordinate with the requirements of PRC-025 Generator Relay Loadability.
- Reference to impedance relays and voltage controlled overcurrent relays was removed from Footnote 1 to eliminate overlap and possible coordination conflict with PRC-025 Generator Relay Loadability.
- Rearrangement of the sentences in Requirement R4 to better clarify that developing the estimate of performance is to be done only upon request of certain planning entities.
- Removal of the Reliability Coordinator and Transmission Operator from the list of functional entities who can request a performance estimate in Requirement R4 and protection settings information in Requirement R6 to eliminate duplication with standards IRO-010 and TOP-003.
- Various wording changes made to improve consistent use of terminology and to improve readability.

Several stakeholders pointed out that a portion of the allowable high frequency trip curve for the Eastern, ERCOT, and Quebec Interconnections (Attachment 1) exceeded the off-nominal frequency limits in IEEE C50.13 and IEC 60034 that are used by equipment manufacturers to design generators. The drafting team revised the high frequency portion of the curve from zero to two seconds for the Eastern and ERCOT Interconnections to meet the IEEE and IEC standards. This leaves no margin between the high frequency allowance for UFLS designers in frequency overshoot for that amount of time, but the drafting team feels this is acceptable.

Coordination with Phase 2 of Relay Loadability – Generation Drafting Team (Project 2010-13.2)

In the previous draft of this standard the voltage ride-through curves in Attachment 2 extended out for 600 seconds before returning to normal operating voltages (95% – 105% of nominal). Also, the final step in the low voltage recovery curve was at 90% of nominal after three seconds. Commenters to the Generator Relay Loadability project pointed out that this could potentially cause conflicts with coordination of settings for relay loadability, since they need to be evaluated for steady-state stressed system conditions of voltages at 85% of nominal. In response, the drafting team has moved the final step of the low voltage recovery curve down from 90% to 85% at three seconds and has shortened the curves so that they end at four seconds. The drafting team believes this clarifies the intent of this standard to address the transient conditions without conflicting with steady state relay loadability.

You do not have to answer all questions. Enter all comments in simple text format. Formatting such as bullets and font changes will not be retained.

NERC

Questions

1. The GVSDT has removed Requirement R5 from the standard. The standard drafting team believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. Do you agree with this revision? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

2. Several stakeholders pointed out that a portion of the allowable high frequency trip curve for the Eastern, ERCOT, and Quebec Interconnections (Attachment 1) exceeded the off-nominal frequency limits in IEEE C50.13 and IEC 60034 that are used by equipment manufacturers to design generators. The drafting team revised the high frequency portion of the curve from zero to two seconds for the Eastern and ERCOT Interconnections to meet the IEEE and IEC standards. This leaves no margin between the high frequency allowance for UFLS designers in frequency overshoot for that amount of time, but the drafting team feels this is acceptable. Do you agree with this change? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

3. In the previous draft of this standard the voltage ride-through curves in Attachment 2 extended out for 600 seconds before returning to normal operating voltages (95% – 105% of nominal). Also, the final step in the low voltage recovery curve was at 90% of nominal after three seconds. Commenters to the Generator Relay Loadability project pointed out that this could potentially cause conflicts with coordination of settings for relay loadability, since they need to be evaluated for stressed system conditions of voltages at 85% of nominal. In response, the drafting team has moved the final step of the low voltage recovery curve down from 90% to 85% at three seconds and has shortened the curves so that they end at four seconds.

The drafting team believes this clarifies the intent of this standard to address the transient conditions without conflicting with relay loadability. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

☐ Yes

☐ No

Comments:

4. Footnote 1 has been revised to remove reference to impedance relays and voltage controlled overcurrent relays which are load-affected protective functions. This was done to remove overlap and potential conflict of coordination with the Generator Relay Loadability project. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

5. Do you have any other comment, not expressed in questions above, for the GVSDT?

   Comments:

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 states "… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "	FERC Order 693	The GVSDT believes that Requirement R2 and the voltage ride through curves in PRC-024 Attachment 2 accomplish this. While the curves were developed based on three phase normally cleared faults located at a generating plant substation (the most severe condition for generating equipment), the curves cover voltages depressed as low as 0.65 per unit for two seconds, which the GVSDT feels will cover the Category B and C events of concern to the Commission. Requirement R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented technical reasons, but directs those generators to communicate that limitation to the PC and TP so its performance can be modeled correctly. In addition, Requirement R4 allows the PC or TP to request an estimate of performance (ride through duration) from the GO for a defined excursion. The estimate would cover process upsets to the generating equipment that might result in a delayed trip, even if the generator protection itself did not cause a trip.

Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 also states "… the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented technical limitations. The GVSDT believes that NRC requirements qualify as technical limitations for the purposes of this standard.

Project 2007-09 Generator Verification
Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
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Project 2007-09 Generator Verification — PRC-024		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		generator protection itself did not cause a trip.
Paragraph 1787 also states "… the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented technical limitations. The GVSDT believes that NRC requirements qualify as technical limitations for the purposes of this standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Performance During Frequency and Voltage Excursions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:
There are five requirements in PRC-024-1. Two of the Requirements (R1, and R2) were assigned a "Medium" VRF and the remaining three requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 and R5, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. . Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The "Lower" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 contains Parts that are procedural in nature defining criteria associated with the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires an estimate of performance and is somewhat similar in concept with both PRC-009-0 Requirement R1 and PRC-014-0 Requirement R2, both of which reference protection analysis or assessment for determining adequacy. In addition, as is generally the case with reliability standard VRF definitions for analysis & assessment planning type requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to estimate performance during a frequency or voltage excursion is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the

emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to estimate performance during a frequency or voltage excursion. Requirement Parts and obligations are lower risk procedure based criteria for the main requirement. The “Lower” VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The "Lower" VRF assigned is based on the reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's reflect increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner per the procedure criteria specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Performance During Frequency and Voltage Excursions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

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The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

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The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:

There are five ~~six~~ requirements in PRC-024-1. Two ~~hree~~ of the Requirements (R1, and R2~~, and R5~~) were assigned a "Medium" VRF and the remaining three requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 and R5, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. . Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5, both of which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The "Lower" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 contains Parts that are procedural in nature defining criteria associated with the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires an estimate of performance and is somewhat similar in concept with both PRC-009-0 Requirement R1 and PRC-014-0 Requirement R2, both of which reference protection analysis or assessment for determining adequacy. In addition, as is generally the case with reliability standard VRF definitions for analysis & assessment planning type requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to estimate performance during a frequency or voltage excursion is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the

emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to estimate performance during a frequency or voltage excursion. Requirement Parts and obligations are lower risk procedure based criteria for the main requirement. The “Lower” VRF assigned is based on the reliability objective specified.

~~VRF for PRC-024-1, Requirements R5:~~

- ~~FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying conditions and exceptions for satisfying the main requirement during external events. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R2, both of which were assigned a “Medium” VRF.~~
- ~~FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires generation to remain connected during external events and as such does not have strong correlation to similar reliability goals listed in different reliability standards. This is similar in scope to Requirement R1 but is applied to new units rather than existing units. Therefore this requirement is assigned a “Medium” VRF.~~
- ~~FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to remain connected during an external event is a requirement during real-time operation that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. Therefore the assigned “Medium” VRF is appropriate.~~
- ~~FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 reliability objective is to remain connected during an external event. Requirement Parts specify conditions and exceptions elements that establish main requirement criteria for completeness. The “Medium” VRF assigned is based on the reliability objective specified.~~

VRF for PRC-024-1, Requirement R5~~6~~:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5~~6~~ does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5~~6~~ reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The “Lower” VRF assigned is based on the reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's reflect increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner per the procedure criteria specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

~~***VSLs for PRC-024-1 Requirement R5:***~~

~~R#~~	~~Compliance with NERC VSL Guidelines~~	~~Guideline 1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~Guideline 2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~Guideline 3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~Guideline 4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~
~~R5.~~	~~The NERC VSL guidelines are satisfied by incorporating binary VSL elements. Requirement Parts merely identify conditions and exceptions for determining binary VSL status.~~	~~This is a new Requirement and does not have a prior level of compliance.~~	~~Proposed VSL's incorporate binary methodology. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance of the actions and obligations specified.~~	~~Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions and exceptions specified by listed parts. Proposed VSL's are consistent with the requirement.~~	~~Proposed VSL's are based on a single violation and not a cumulative violation methodology.~~

VSLs for PRC-024-1 Requirement R~~5~~6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2007-09 Generator Verification
PRC-024-1

Successive Ballot and Non-binding Poll is now open through Friday, January 11, 2013

Now Available

A successive ballot of **PRC-024-1** and non-binding poll of the associated VRFs and VSLs is now open through **8 p.m**. **Eastern on Friday, January 11, 2013**.

The other four standards in this project were posted for a recirculation ballot and the results were announced on December 21, 2012.

Instructions
Members of the ballot pools associated with this project may log in and submit their vote for the standard and opinion in the non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background
The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid-2006 through mid-2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Additional information is available on the project page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 Generator Verification
PRC-024-1

Formal Comment Period: December 12, 2012 – January 11, 2013

Upcoming:
Successive Ballot and Non Binding Poll: January 2, 2013 – January 11, 2013

Now Available

A 30-day formal comment period is open for **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions through **8 p.m. Eastern on Friday, January 11, 2013**.

A successive ballot of **PRC-024-1** and non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Wednesday, January 2, 2013 through 8 p.m**. **Eastern on Friday, January 11, 2013**.

The remaining four standards in this project are being posted for recirculation ballots from December 12, 2012 through December 21, 2012. A separate announcement will be sent for these recirculation ballots.

Instructions for Commenting
A formal comment period for **PRC-024-1** is open through **8 p.m. Eastern on Friday, January 11, 2013**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background
The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such

coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

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Project 2007-09 Generator Verification
PRC-024-1

Formal Comment Period: December 12, 2012 – January 11, 2013

Upcoming:
Successive Ballot and Non Binding Poll: January 2, 2013 – January 11, 2013

Now Available

A 30-day formal comment period is open for **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions through **8 p.m. Eastern on Friday, January 11, 2013**.

A successive ballot of **PRC-024-1** and non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Wednesday, January 2, 2013 through 8 p.m**. **Eastern on Friday, January 11, 2013**.

The remaining four standards in this project are being posted for recirculation ballots from December 12, 2012 through December 21, 2012. A separate announcement will be sent for these recirculation ballots.

Instructions for Commenting
A formal comment period for **PRC-024-1** is open through **8 p.m. Eastern on Friday, January 11, 2013**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background
The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such

coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
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Standards Announcement

Project 2007-09 Generator Verification
PRC-024-1

Successive Ballot and Non-Binding Poll Results

Now Available

A successive ballot of **PRC-024-1** and non-binding poll of the associated VRFs and VSLs concluded at **8 p.m. Eastern on Friday, January 11, 2013**.

Voting statistics for each ballot are listed below, and the Ballot Results page provides a link to the detailed results.

Approval (Updated)	Non-binding Poll Results (Updated)
Quorum: 78.16% Approval: 60.31%	Quorum: 76.38% Supportive Opinions: 55.68%

Next Steps

The drafting team will consider all comments received during the formal comment period to determine the next steps.

Background

The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

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The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Updated

Ballot Results	
Ballot Name:	Project 2007-09 Successive Ballot PRC-024-1
Ballot Period:	1/2/2013 - 1/11/2013
Ballot Type:	Successive
Total # Votes:	247
Total Ballot Pool:	316
Quorum:	78.16 % The Quorum has been reached
Weighted Segment Vote:	60.31 %
Ballot Results:	The drafting team will review comments received.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	82	1	33	0.579	24	0.421	12	13
2 - Segment 2.	6	0.3	1	0.1	2	0.2	2	1
3 - Segment 3.	68	1	26	0.591	18	0.409	8	16
4 - Segment 4.	25	1	8	0.5	8	0.5	3	6
5 - Segment 5.	76	1	23	0.469	26	0.531	9	18
6 - Segment 6.	42	1	18	0.621	11	0.379	3	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.3	2	0.2	1	0.1	1	4
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.6	6	0.6	0	0	0	1
Totals	**316**	**6.4**	**119**	**3.86**	**90**	**2.54**	**38**	**69**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	paul B johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai		
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Abstain	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney		
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Manitoba Hydro	Greg C. Parent		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	

3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Cowlitz County PUD	Bob Essex	Negative	

5	CPS Energy	Robert Stevens	Abstain	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn		
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda L Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		

6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen		
6	South California Edison Company	Lujuanna Medina	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz		
8		Merle Ashton		
8		Brendan Kirby	Affirmative	
8		James A Maenner	Abstain	
8		Edward C Stein		
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Non-binding Poll Results

Project 2007-09 PRC-024-1

Non-binding Results	
Non-binding Poll Name:	Project 2007-09 Non-binding Poll PRC-024-1
Poll Period:	1/2/2013 - 1/11/2013
Total # Opinions:	235
Total Ballot Pool:	309
Summary Results:	76.38% of those who registered to participate provided an opinion or an abstention; 55.68% of those who provided an opinion indicated support for the VRFs and VSLs. (UPDATED)

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	paul B johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	

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1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Abstain	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis		
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	PacifiCorp	Colt Norrish	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	

1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
2	Alberta Electric System Operator	Mark B Thompson		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren	Negative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	Southwest Power Pool	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney		
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	

3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	

4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Cowlitz County PUD	Bob Essex	Negative	
5	CPS Energy	Robert Stevens	Abstain	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	

5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Abstain	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn		
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	

5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	William T Moojen		
6	South California Edison Company	Lujuanna Medina	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz		
8		Brendan Kirby	Affirmative	
8		James A Maenner	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	

8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Texas Reliability Entity	Larry D. Grimm	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Name (34 Responses)
Organization (34 Responses)
Group Name (16 Responses)
Lead Contact (16 Responses)
Contact Organization (16 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (3 Responses)
Comments (50 Responses)
Question 1 (39 Responses)
Question 1 Comments (47 Responses)
Question 2 (29 Responses)
Question 2 Comments (47 Responses)
Question 3 (33 Responses)
Question 3 Comments (47 Responses)
Question 4 (33 Responses)
Question 4 Comments (47 Responses)
Question 5 (0 Responses)
Question 5 Comments (47 Responses)

Group
Arizona Public Service Company
Janet Smith
Arizona Public Service Company
APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
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Individual
mon
test
Yes
test
No
Yes
pp
No
no
Group
pacificorp
ryan millard
pacificorp

Yes
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
Yes
Yes
The Curve Data Points table on page 18 of Draft 5 has not been updated to reflect the changes mentioned above.
Yes
Individual
Ken Gardner
Alberta Electric System Operator
No
The AESO disagrees with this requirement being removed from Draft 5 and believes that new generating must be required to be designed, built and maintained in compliance with PRC-024-1 unless it is due to equipment failure and in such cases the owner of the generating unit must report failure to the ISO with a plan to address the failure.
No
The AESO disagrees with the use of 85% and supports the values as expressed previously in draft 4 of PRC-024-1. Transmission systems are designed to operate between 90% to 110% and not down to 85%, as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. In particular, as NERC has left the 85% duration open ended, it is unclear how long a generating unit is to remain on-line under this condition. In addition, there appears to be a discrepancy in Attachment 2 where the "Curve Data Points" table identify a low voltage ride through duration of 600 seconds for <0.90 pu voltage and the "Voltage Ride Through Time Duration Curve" shows this to occur <0.85 pu voltage. Based on the explanation above, the table should be updated accordingly.
Individual
John Bee
Exelon Corporation and its affiliates
Exelons negative vote is based on the following: Exelon reiterates that nuclear generating units must comply with a rigorous process of evaluation to meet requirements of the Nuclear Regulatory Commission (NRC). The response by the SDT in the Consideration of Comments dated 12/7/12 that "the SDT does not believe extensive studies or dynamic simulations are required to comply with this requirement" does not address the fact that NRC licensed nuclear generating units must also comply with the requirements of the NRC. Exelon again does not agree that 60 calendar days is a reasonable amount of time to perform any such analysis.
Individual
Jim Keller
We Energies
No

The NAGF agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that “No concrete data on which to base judgments – assume tripping,” is an acceptable response.
Yes
Yes
Yes
The NAGF also recommend the following changes to Footnote 1. The expression, “protective functions within control systems…based on frequency or voltage inputs,” should be replaced with, “control system frequency or voltage trip setpoints.” It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, “known equipment limitation…including (but not limited to) study results, experience from an actual event, or manufacturer’s advisory.” Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
a. Confusion is created by making exemptions, “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such “protective relays” meant to correspond to the “protective relaying” discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.” Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed . b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn’t be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. d. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
Individual
Patrick Brown
Essential Power, LLC
No
We agree with the removal of R5, but am still concerned with the criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear

concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that “No concrete data on which to base judgments – assume tripping,” is an acceptable response.
Yes
Yes
Yes
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Individual
Louis C. Guidry
Cleco
Yes
Cleco is concerned the approach is too prescriptive given the numerous variables associated with generator performance and protection. We recommend the elimination of requirements R1 and R2 in their entirety. We further recommend requirement R3 be modified so that the generator owner is required to develop a unit capability curve for frequency and voltage based on equipment limitations and protection requirements and provide this information to the appropriate users. This approach emphasizes equipment preservation and safety while retaining predictability of unit performance for system modeling. We would also like an example for how to evaluate Volts/Hertz protection for the proposed voltage curve.
Individual
Michelle DAntuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP is firmly in agreement with the removal of the ride-through performance requirement (R5) from PRC-024-1. Although we understand the intent to guarantee generation availability for a set of voltage and frequency transients, the project team has correctly determined that the costs far outweigh the benefits. In our view, this is in keeping with the spirit of the

Cost Effective Analysis Process, Paragraph 81, and other risk-based compliance initiatives that were initiated to maintain that careful balance.
While we were pleased to see the removal of R5 from PRC-024, there is still some question as to the basic necessity for this standard, PRC-001, now PRC-027, requires extensive coordination of protection system relay setting between GOs and TOs. Interconnection agreements also require following voltach schedules, etc. This is a case of over regulation and portential conflicts between standards, something Paragraph 81 initiative is supposed to oppose. Also, there is no explicit FERC directive that requires this standard.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Yes
Yes
Yes
Yes
Group
Salt River Project
Bob Steiger
Electric Reliability Compliance
Yes
Yes
Yes
Yes
Individual
David Jendras
Ameren
Yes
Yes
Yes
Yes
The SDT has addressed all of our comments by changing several items that improve the standard, and especially important to us was removing R5 & M5. However, the SDT did not alter the VSL from the 10 day escalation for R3 through R5, and used the NERC guidance as their reason. NERC guidance also allows for a population based severity escalation, which we believe is more appropriate for characterizing the severity in situations such as this, and so we recommend using this approach. We suggest allowing up to 5% for Low, 5 to 10% for Moderate, 10 to 15% for High, and greater than 15% for Severe. For example, change the R4 Lower VSL to “The Generator Owner provided an estimate for less than 100% but more than 95% of its units’ performance within 60 calendar days of a written request” and change R4 Moderate VSL to “The Generator Owner provided an estimate for 95% or less, but more than 90% of its units’ performance within 60 calendar days of a written request.”
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes

Yes
Yes
Yes
1. The word "evidence" is missing in Measure M2. Also in Measure M2, the wording should be changed to add the phrase, "... or other documentation", to the list of acceptable evidence for Requirement R2. Measure M1 allows "other documentation" as evidence, and this should be true for Measure M2 also. 2. We disagree that the applicability of this standard needs to be to all generators regardless of size or connection voltage. Only generators connected to the Bulk Electric System should be applicable. The efforts needed to meet these requirements will be significant, and should not be required for every generating unit. Please verify your understanding of the referenced FERC order, because resources are limited.
Group
Southwest Power Pool Reliability Standards Development Group
Jonathan Hayes
Southwest Power Pool
Yes
No
Our concern is by eliminating the instantaneous high frequency overshoot margin that you could cause an unintended cascading event on the system. For example when you drop load it could cause an instantaneous unit trip, due to instantaneous high frequency on the unit, which would then cause an under frequency load trip. We would suggest that the drafting team let the regions investigate before approving this reduction in the margin for this time period and standard as a whole.
No
We would like to see consistency between the voltage ride through curve and the off nominal frequency capability curve in the log scale. The last draft was consistent and we wonder why the drafting team changed the voltage ride through curve to a linear depiction?
Yes
Individual
Jonathan
Appelbaum
The VRF for R1 and R2 should be High not Medium. The Drafting team in the VRF justification document states [Start quote] This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated.[End Quote] I disagree with the assertion. PRC-023 is violated if one relay is incorrectly set regardless of the number of elements it is protecting. The same applies to PRC-024, a failure to set one relay will effect one generator. Also for PRC-023 a single violation would not lead to BES cascade but that reasoning did not prevent a VRF of High to be established for PRC-023. Applying consistent reasoning to PRC-024 would mean that the single generator argument to reduce the VRF to medium wuld not apply.
Individual
Keith Morisette
Tacoma Power
Yes
Yes
Yes
Applicability should only be to those units meeting NERC registration criteria. Per Footnote 4, the “point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.” As the SDT is probably aware, many generator protective relays measure voltage on the generation (low voltage) side of the transformer. It seems that guidance may

be needed to reconcile generation (low voltage) side measurements with a standard whose requirements are based upon transmission (high voltage) side voltage. In R2, the phrase “less stringent” may not be clear enough language. For example, could “less stringent” mean 96-104%, rather than 95-105%, which is our assumption? Or, could it mean 94-106%? Why are auxiliary systems mentioned in R4 but not in R1, R2, and R5? In R5, remove parentheses around “that models the associated unit.” The parentheses seem to be inconsistent with similar text in R4. In M2, move ‘evidence’ to before “that generator voltage…” Attachment 2, Curve Detail 3, may need some better clarification. Regarding Attachment 2, Curve Detail 4, does that mean a GO must base relay settings on the lowest expected frequency deviation? What is an example of how and when Detail 4 should be applied? Regarding Attachment 2, Curve Detail 5, by stating “RMS or crest”, does this mean that a GO must consider harmonics? Most simulations only consider the fundamental frequency component. In these cases, the per unit crest and RMS voltage should be identical. Clarification is requested. Examples are needed to support the application of Attachment 2, Evaluating Protective Relay Settings. R1, R2, and the diagram in Attachment 2 appear to be fairly straightforward. However, the Voltage Ride-Through Curve Clarifications page (last page) seems to confuse, not clarify. This last page seems to undermine the apparent simplicity of the rest of the standard with respect to voltage protective relay settings. In Attachment 2, the Curve Data Points table needs to be updated to reflect the Voltage Ride-Through Time Duration Curve. Tacoma Power appreciates the opportunity to provide comments, and thanks you for consideration of our comments.
Group
IRC Standards Review Committee
Charles Yeung
SPP
Yes
No
We are concerned about how this change may impact the how the system responds to frequency excursions. Please refer to our comment in question 5.
Yes
Yes
In order for the industry to support the proposed change to the high frequency trip curve in Attachment 1, we propose that the SDT provide the technical justification and an assessment of the system impacts as a result of the proposed change so operators are aware of and manage the resultant system response. We believe the standards should be based upon actual technical data rather than conditions represented in the IEEE and IEC standards.
Group
seattle city light
paul haase
seattle city light
Seattle CIty Light, from a GO perspective, will vote NO, becasue it is unclear the type of data the TP is to provide the GO. Until the TPs agree to and approve acceptable simulations and dynamic models, it is difficult for the us to approve this standard.
Group
Dominion
Connie Lowe
Dominion
Yes
Yes
Yes
Draft 5 Page 16 (clean version) the Curve Data Points table has not been updated to reflect the changes mentioned in question #3 above. Dominion agrees with the changes provide this modification is made.
Yes
Individual
Anthony Jablonski
ReliabilityFirst

ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comment for consideration: 1. Requirement R3 Part 3.1 a. To be consistent with the changes made to Requirement R4 and new R5 (removal of Reliability Coordinator and Transmission Operator), ReliabilityFirst recommends removing references to the Reliability Coordinator and Transmission Operator from Requirement R3 Part 3.1 as well. Requirement R3 is long-term planning requirement and communication of the documented equipment limitations to these entities should not be required.
Individual
Michelle Clements
Wolverine Power Supply Cooperative, Inc.
Yes
Yes
Yes
Yes
The applicability should be restricted to BES generating units, not all units.
Individual
Kathleen Goodman
ISO New England Inc.
Yes
No
Yes
The curve data points chart was not revised when the drawing (including timescale) was revised. This leads to confusion however overall the change shown in the curve to 0.85 is acceptable.
Yes
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Yes
Yes
Yes
Yes
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
Yes

Yes. First, the standard as presented is greatly improved from the prior version. The hard work of the SDT is apparent. However, there still are a few issues which should be resolved with the standard. First, the 10% trigger for removing exemptions is too low. GE markets products for their gas turbines which can raise output more than 10% through software changes. This could place a turbine into no exemptions space while it still contained blades subject to failure at frequencies within the no trip zone. The 10% threshold should be raised or the standard reworded to note that software changes do not trigger the requirement. Secondly, the phrase "manufacturers advisory" is too vague. One reasonable person may read the phrase as "a statement in the OEM materials which places limits on the frequencies the machine can tolerate", while another reasonable person would define it as "a specific bulletin or technical information letter which advises of a finding about the equipment". GE 7FA OEM documents, for example, state that the turbine is "very sensitive to abnormal frequencies" and that recommendations "should be carefully studied and followed". Would this document, coupled with an engineer determining an overfrequency relay setting of 60.5 with 60 cycle delay, be enough to allow that setting? Would something like this be subject to individual auditor determination? If the latter is true, the wording should be changed, as requirements should clearly guide the entity in making a determination of the allowable action. Finally, if a steam turbine which is driven by steam generated from gas turbine exhaust is required to trip within the no-trip zone due to equipment limitations, does this allow those gas turbines to trip within the no trip zone also, in order to prevent damage to the steam turbine condenser? Can their protective settings for overfrequency be set at the same point as the required steam turbine settings, or would an entity have to add logic to their system to trip in response to the activation of the steam turbine overfrequency trip instead of their own overfrequency relay?
Individual
Thad Ness
American Electric Power
Yes
Yes
Yes
Yes
We agree with the overall approach taken, however we are concerned that the standard repeatedly references "protective relaying" while Footnote 1 clarifies that protective relaying could be discrete relays as well as protective functions within control systems. The term "protective relay" is widely accepted amongst engineers as meaning a discrete relay. AEP recommends the SDT utilize the term "protective functions" throughout the standard to clearly identify that the scope of the standard extends beyond discrete relays. AEP recommends that the time allowed to meet R 3.1 be extended to 60 calendar days, aligning it with R4 and R5. AEP recommends R4 and R5 be revised to read "within 60 calendar days or an agreed upon schedule". The data sought by the PC or Transmission Planner might be quite large for some utilities. In this case, it would be advantageous to allow the GO to work with the requesting party to develop a timeline that meets the needs of the requesting party without being overly burdensome to the GO. We believe the intent of the SDT in requiring the GO to provide updates on any previously requested trip settings in R5 was to ensure that the PC and TP are notified of any changes to the R1 and R2 applicable trips. If this is accurate, we suggest revising R5 to require the GO to update the PC and TP within 60 days of installation of new trips or changes to existing trips to which R1 and R2 applies, not solely those trip settings previously requested by the PC and TP. Doing so removes the obligation of the GO to track which trip settings were part of a previous request. This change will also eliminate the possibility of the TP or PC not being made aware of a newly installed applicable trip within a timely fashion. Should the 10 percent generator nameplate capacity increase stipulation in the last (fourth) bullet point under R3.1 be removed? We do not see that the stipulation is relevant to the question of what limitation is causing a given generating unit to not satisfy R1 or R2 criteria. Perhaps the point should read as follows: “Modification or upgrade of the equipment causing the limitation that removes or changes the limitation.” With reference to R4, would it make sense for the TP or PC to specify Attachments 1 and 2 as the profiles for the purpose of collecting time duration estimates, or should the term “profile” instead be “trajectory”? From the viewpoint of the TP or PC, receiving duration estimates with respect to the Attachments would be advantageous, particularly when coordinating generator off-nominal frequency tripping with UFLS. However, a single duration estimate seems more compatible with a frequency or voltage trajectory. Which is the SDT’s intent?
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
(1) R4 – the word ‘for’ is missing between duration and which. (2) R4, second paragraph – the requirement hinges on what the GO ‘expects’ may happen, is very subjective. It will be hard for the MRO to measure compliance on this point. The phrase ‘for the duration of the profile of the excursion’ is new and not language that appears anywhere else in R4. It’s not clear what it means. We would suggest using language that appears in the first paragraph of R4 so this is consistent. (3) R5 – allows the Planning Coordinator or Transmission Planner to request that settings must be provided within some time frame other than 60 days if they so direct. Theoretically this could be 1 day as there are no parameters put on what the PC or TP may direct. (4) R5 - doesn’t provide for a time frame other than 60 days which the requirement does. (5) M2 - the word 'evidence' should be placed after ‘have’

and not after ‘R2’. (6) M3 – language doesn’t seem to reflect revisions made to R3. For example, ‘excluding limitations…’ is still in M3 but deleted from R3. (7) M4 – language doesn’t seem to reflect revisions made to R4. For example, the description of the generating units differs. (8) M5 – does not contemplate that it may be some time frame other than 60 days as R5 permits. (9) Compliance, 1.1 – CEA is used in the last sentence but never defined. The acronym is not used again, so it’s likely easiest to not define it and use Compliance Enforcement Authority each time. (10) VSLs, R1 and R2 – the wording of the VSL is problematic as it ties the violation to a violation of R3 which the requirement itself does not do.
Group
Tennessee Valley Authority
Brandy Spraker
NERC Compliance
No
Recommend that the R4 be enhanced to give more detail on how to satisfy this requirement. As significant as R4 is, the Generator Owners need more guidance than what is currently stated.
1. The technical justification for the need of a plant performance criteria appears to be based on issues with early design wind generation. The technical considerations at these types of generation stations are different than steam turbine generation plants, which require heavy induction loads to support operation and these loads are sensitive to upsets in voltage and frequency. The technical implications of the plant performance are not clear. Recommend generating a separate SAR and bring in industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical acadamia, etc. to assist in the technical analysis and standard development. 2. Likewise, industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical acadamia, etc. can develop acceptable methods to determine the capability of a plant to ride through grid transients. 3. The following are IEEE Electric Machines Committee comments for PRC-024-1 consideration The IEEE Electric Machinery Committee hosted a discussion topic on “Grid Code Impact on Electric Machine Design” in San Diego at this year’s Power Engineering Society meeting and offers the following input. • Minor changes in the Under-frequency Ride Through Curve are suggested to better match existing machine design standards in IEEE C50????. • The PRC-024 Voltage Ride Through criteria is technically not ready to be a standard, for the following reasons; 1. PRC-024 VR capability may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. It is believed the cost of complying with wider standards might increase main generator machine costs as much as 25%, which is not insignificant. This should only be required if there is a defined local system need for higher standards and that these costs should be considered against the cost of other possible resolutions. 2. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of all 4160V and 460V systems in new plant can be dynamically modeled to a degree allowing one to obtain non-dropout guarantees from equipment suppliers and EPC firms for extreme transients such as 2.0 seconds at 65% voltage, or that the same can be done for existing plants to allow identification of limiting components and accurate estimates of performance. 3. The voltage ride through was originally intended to address early deficiencies in wind generation design only and it doesn’t make sense to apply such a broad curve to steam plants. The concerns that led to the VRT curve for wind have been addressed by new vintage wind plant designs and thus, the EMC does not believe there is not driving need for a standard VRT criteria. • The VRT issue is holding up addressing other significant issues addressed by PRC -024 (relay setting coordination and frequency ride through). The VRT should be pulled out of PRC-024 and a new SAR drafted to address the voltage performance aspects if this is really needed for reliability. • More clarity in defining plant MVARs available to support grid voltage is needed. Specifically, generation plants have not been designed to operate outside a normal band of 95 to 105% on the generator terminals. GSU settings are typically chosen to optimize MVAR support under normal operations, however is not reasonable to assume the full leading or lagging reactive support would be available under normal grid conditions.
Individual
Mike Hirst
Cogentrix Energy Power Management, LLC
No
The NAGF agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that “No concrete data on which to base judgments – assume tripping,” is an acceptable response.
Yes
Yes

Yes
The NAGF also recommend the following changes to Footnote 1. The expression, “protective functions within control systems…based on frequency or voltage inputs,” should be replaced with, “control system frequency or voltage trip setpoints.” It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, “known equipment limitation…including (but not limited to) study results, experience from an actual event, or manufacturer’s advisory.” Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
a. Confusion is created by making exemptions, “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such “protective relays” meant to correspond to the “protective relaying” discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.” Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed . b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn’t be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation.
Group
Duke Energy
Greg Rowland
Duke Energy
Yes
Yes
Yes
Yes
a) The effective date in Section 5.1.4 should be increased to seven years. The typical major outage cycle for base load units can be as long as 7 to 9 years, based upon the unit and its history. b) In the “Consideration of Issues and Directives” document, it is stated that the GVSDT believes that R3 allows NRC requirements to supercede portions of the voltage and frequency ride through criteria in PRC-024-1, and that NRC requirements qualify as technical limitations for the purposes of this standard. We believe that additional clarity is needed in the text of Requirement R3 regarding allowable limitations other than equipment limitations, such as NRC technical specification limits and perhaps environmental permit limitations as well. c) Additional clarity is needed in Requirement R4. Is R4 intended to serve as a means to obtain more information from a Generator Owner about limitations identified pursuant to R3? Is the voltage or frequency profile to be provided by the Planning Coordinator or Transmission Planner different from Attachments 1&2? d) Requirement R4 states that the Generator owner may develop estimates based upon “sound engineering judgment”. R4 should more clearly indicate the extent of “due diligence” effort that is expected in order to support an estimate based on “sound engineering judgment”. e) On Attachment 2, Evaluating Protective Relay Settings, 1.c states that “Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.” We believe that compensating all generator voltage relaying for a loading of rated power at 0.95pf lagging is dangerous, as this could indicate coordination margin to the HVRT when there is none. The worst case coordinating conditions for the HVRT are not the same as for the LVRT. The current version of the standard is prescribing a method that will lead to miscoordination between the HVRT curve and overvoltage relays (59 & 24 elements). We recommend generator undervoltage relaying be evaluated at rated power at rated powerfactor, and generator overvoltage relaying be evaluated at rated power at .95pf leading. There can be more than a 10% difference in POI voltage under these two sets of conditions. f) In the VRF and VSL Assignment document, the R6 should be corrected to R5 (typo)
Group
MRO NSRF

WILL SMITH
MIDWEST RELIABILITY ORGANIZATION
Yes
Yes
Could the drafting team please clarify the risk to the BES by leaving no margin for frequency overshoot? The NSRF was unsure if reducing the no trip margin above the IEEE / IEC design limits really represented a reliability risk to the BES. If generator units do overshoot the IEEE / IEC curve and remain on-line without damage, that doesn't appear to be a reliability risk. If the generator should trip to avoid damage from a frequency overshoot above the IEEE / IEC curve for which the unit was designed, that would also appear to be better for reliability, even if the unit does trip.
Yes
The NERC generator relay loadability standards don't appear to state times, so changing the curves from 600 seconds to 3 and 4 seconds is a step in the right direction but could still lead to conflicts unless this standard or PRC-025 is amended. In a relay world that typically operates in cycles, 3 to 4 seconds is still a very long time and the NSRF believes that conflicts are still possible unless both standards are coordinated carefully. It is inappropriate to force entities to chose which standard to potentially violate. Please make sure that the associated graphs and curves data points within the table match each other.
Yes
In R3, the NSRF recommends that 30 day requirement be replaced with "in a timely manner not to exceed 90 days". This is predicated on the low VRF and low risk of impacting the BES. While some deadlines are necessary in NERC standards, large frequency and voltage ecursions are rare and there would be little to no reliability difference if R3 changes were communicated in a time frame longer than 30 days. In R3, the fourth bullet, delete (cumulative from the first effective date of this standard). This creates an unnecessary compliance tracking burden. Entities must forever memorialize all equipment capability from the effective date of the proposed standard such as 2014. There is no reason to track all possible equipment changes in 2044 back to 2014 to show that a 10% upgrade has not occurred is pieces throughout the years. Transmission and generation upgrades are usually lumped and somewhat large as it is usually cost prohibitive to increase generator capability. The reliability benefit is to recognize when a large change in the limitation occurred, not to track a cumulative 10%. Is the SDT referring to only the limiting element that needs to be tracked?
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
PPL Generation, LLC on behalf of its Supply NERC Registered Entities
No
Although PPL Companies agree with the removal of R5, PPL is still concerned with the following criteria stated in R4. R4 allows using, "experience, actual event histories, or sound engineering judgment," to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word "sound" implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis we could make regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit in the fleet, "Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered," (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance. For R4 to reach this goal we believe that PRC-024 Measure 4 should state that "No concrete data on which to base judgments – assume tripping," is an acceptable measure for R4.
No
Yes
Yes
The PPL Companies also recommend the following changes to Footnote 1. The expression, "protective functions within control systems…based on frequency or voltage inputs," should be replaced with, "control system frequency or voltage trip setpoints." It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation…including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
Confusion is created by making grandfathering (exceptions), "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such "protective relays" meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any grandfathering is actually being allowed. It has been said in discussions with the SDT that there is no grandfathering of voltage-relaying or frequency-relaying intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations is in fact where our over/under-frequency protection system settings come from. If a turbine OEM notifies us that a unit must trip within one second at 2.5% overspeed, for

example, then our 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.” Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on historical practice with an unknown technical basis, a more direct way of saying so should be developed. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn’t be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. It would be acceptable if R3.1 or a footnote stated that “Resubmittal of the exemption documentation when reporting a 10% increase in nameplate capacity is required, but the removal of the exemption status is not required as part of the 10% increase in nameplate capacity.” Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
1) Sacramento Municipal Utility District (SMUD) believes the applicability section should be revised to only cover those units defined by the BES Definition. As currently drated Generator Owners that are registered under the NERC Registry Criteria along with other non-registered generator owners are subject to this standard causing an enforcement issue. 2) SMUD thanks the SDT for their response to our comment on R6 (now R5) during the last posting. However, SMUD wishes reiterate our disagreement with a requirement mandates ALL generator protection settings. SMUD also find it problematic to allow a single request by the PC or TP to create an indefinite requirement to report any relay change. SMUD believes R5 should be limited in its applicationto only frequency or voltage settings that directly correspond with the measure the PC or TP implement in their studies.
Individual
Scott Kinney
Avista
Yes
Most frequency relays have voltage supervision. There is no voltage supervision requirement for frequency relays specified in the standard. For the voltage relay settings the ride through is given as 9 cycles at 0 volts. Where did the 9 cycles come from?
Individual
Mike Hendrix
Idaho Power Company
Idaho Power’s Power Supply group feels that Requirements 1 through 4 accomplish the purpose of PRC-024 and that Requirement 5 is not necessary and in fact creates an on-going obligation for the generation owner to continually provide relay settings to the Transmission Planner within 60 days of any change to those settings regardless of the relay setting changes impact on reliability and even if the changed settings remain in compliance with R1 and R2 of the standard. However, Idaho Power’s System Planning group feels that Requirement 4 is not a sufficient mechanism to collect the desired data and removal of R5 will limit the Planning Authority’s ability to request relay modeling data from both Idaho Power and non-Idaho Power Generator Owners. R5 will make it a

compliance obligation for GOs, to provide the required data when requested by a PA/PC or TP in a timely manner, or following a change in relay settings on a generator for which said data had previously been requested. Idaho Power notes the Measure 2 should read: Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies." Idaho Power comments that reference to the Planning Coordinator entity throughout the PRC-024 standard should be replaced with the term Planning Authority to be consistent with the NERC Glossary of Terms.
Group
Southern Company
Bill Shultz
Southern Company Services, Inc
Yes
Yes
Yes
Yes
1) Add the word "evidence" between "shall have" and "that" in M2 (to match the wording of M1). 2) We believe that R4, due to the uncertainty of speculating the probability of the unit ride-thru/trip when exposed to transmission system voltage and frequency excursions described by Attachment 1 and Attachment 2, will not yield beneficial information in support of the BES reliability. 3) The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. 4) Delete the word "nameplate" on item 1.b on the last page of the draft standard under "Evaluating Protective Relay Settings" for voltage excursions. The language "full real-power output" enables GOs to use the best "full load MW" values they have for their units for plant-specific studies.
Individual
Melissa Kurtz
US Army Corps of Engineers
Agree
MRO NSRF
Individual
Kenneth A Goldsmith
Alliant Energy
Agree
MRO NSRF
Individual
Brett Holland
Kansas City Power & Light
Yes
Yes
Yes
Yes
Comment 1; Generator protective relays are connected to the potential transformers on the generator side of the GSU transformer. The interconnection point is defined by the standard on the transmission side of the GSU. The voltage and frequency charts in the attachments are requirements at the interconnection point. Therefore the standard prevents the use of existing generator protective relays for voltage or frequency protection. The standard and attachment charts should be redrafted to represent the interconnect point on the generator side of the GSU so existing multifunction relays can be used for voltage and frequency protection. Comment 2; Requirement 5 states "Generator Owner shall provide its generator protection trip settings to the Planning Coordinator, etc". In the context of this standard I would assume that generator protection trip settings would be those settings relative to voltage or frequency protection and for example would not include back up distance settings. The standard should be modified to clarify which generator protective relay settings are required for compliance.
Individual
Michael Falvo
Independent Electricity System Operator
No

This should be confirmed with the UFLS designers in conjunction with PRC-006 and PRC-006-NPCC to see how this is coordinated with the frequency overshoot for that amount of time.
Yes
No
The standard clearly specifies in R1 and R2 that frequency and voltage relaying should not operate within "no trip zone". Footnote 1 should be completely removed since is only an incomplete list of the posible generator protections.
Individual
Joylyn Faust
Consumers Energy Company
No
Consumers Energy is resubmitting our original comments as we feel they still pertain. “Related to undervoltage criteria, the 18 cycle at 45% of generator voltage would put a great deal of strain on the plant auxiliary systems and that may not be something these systems are able to withstand. The same would be true of a fault that produces 65% voltage at the generator terminals for 2 seconds. These comments relate specifically to Consumers Energy. However, it is likely that many others have similar equipment and would have the same issues. Please also note that the proposed standard does not align with ANSI C37.102, IEEE Guide for AC Generator Protection or with the NERC Technical Reference Document entitled Power Plant and Transmission System Protection Coordination.” Previous SDT reply - Thank you for your comments. Please note that the voltage levels specified in Attachment 2 are at the point of interconnection to the transmission system. They would not correlate directly with the auxiliary bus voltages, especially if the auxiliaries are unit-connected. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. Please inform the SDT of the specifics of your concerns.” We believe our comments still apply. Specific to the fault that produces 65% voltage at the generator terminals for 2 seconds, plant auxiliary equipment would not be able to withstand such a drop for the specified duration and would fall offline. SDT Reply - The SDT thanks you for your comments. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. The SDT believes that the wording of R4, "The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment," will allow the GO to provide an estimate. However, if the GO feels his equipment is not capable of meeting the undervoltage criteria of Attachment 2, then R3 would apply. Also, note that Attachment 2 has been modified for the next draft and now only extends to 4 seconds.
Individual
Michael Goggin
American Wind Energy Association
No
AWEA does not support this revision, but does not wish to hold up the standards development process for PRC-024. AWEA strongly supported keeping the standard as a generator performance standard, believing that the standard would result in improved electric reliability. AWEA also supports NERC taking the lead in setting national reliability standards, instead of the far less efficient outcome of individual regions advancing their own reliability standards. Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard.
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Program
Yes
Yes
Yes
Yes
BPA believes that the standard should combine bullet 3 into bullet 2 in R3.1 (and modify bullet 3 to notify when equipment has been replaced for whatever reason) • Identification of an equipment limitation. • Repair or replacement of the equipment causing

the limitation that removes the limitation. • Replacement of the equipment causing the limitation. (modification)
Individual
Brad Harris
CenterPoint Energy
No
CenterPoint Energy previously expressed concern that the proposed standard does not impose any minimum frequency or voltage ride-through requirements for existing generating stations. With this proposed revision, the standard will not even impose any minimum requirements for new generating stations. Failure of a generating unit to ride-through at least some minimum threshold of frequency and voltage excursions places the reliability burden solely on transmission entities. This makes is difficult to compensate for the generator's failure to perform and, therefore, is problematic for BES reliability.
No
CenterPoint Energy agrees with lowering the low voltage recovery curve down from 90% to 85% at three seconds; however, CenterPoint Energy is concerned with truncating the curves at 4 seconds due to undervoltage load shedding (UVLS) and relay loadability factors. For coordination with UVLS systems, CenterPoint Energy recommends the curve be extended to at least 10 seconds. Additionally, the purpose of relay loadability standards is to allow sufficient time for system operators to take corrective actions. Based on the purpose of relay loadability, CenterPoint Energy believes the curves should remain extended through 600 seconds.
No
CenterPoint Energy does not agree with removing references to impedance relays and voltage controlled overcurrent relays in Footnote 1, as we are concerned that there could be some differences between relay loadability and low voltage ride-through. Voltages at 85% of nominal and emergency current levels are used for calculating relay set points for relay loadability. For low voltage ride-through, impedance relays and voltage controlled overcurrent relays would need to be evaluated at voltage levels as low as 0% of nominal and at short circuit fault current levels. Instead of removing these relays from Footnote 1 at this late point in the development of PRC-024, CenterPoint Energy suggests that this be addressed by the SDT for PRC-025 Generator Relay Loadability. The PRC-025 SDT has the appropriate subject matter expertise to fully vet whether these types of relays should be removed from PRC-024.
CenterPoint Energy does not agree that a Planning Coordinator or a Transmission Planner should be required to provide a voltage or frequency profile at the point of interconnection that is determined by dynamic simulation and, instead, recommends that the voltage or frequency profiles in Attachment 1 and Attachment 2 be referenced. Different types of simulated events will produce different voltage and frequency excursions. Also, even the same type of event will produce different voltage and frequency excursion "profiles" as the system changes over time. Therefore, the voltage or frequency profiles in Attachment 1 and Attachment 2 should be used.
Group
ACES Standards Collaborators
Jason Marshall
ACES
Yes
Thank you for making this change.
No
While we are not opposed to this change per se and do not offer any suggested alternatives, we would like to see a technical justification for why this is acceptable. The only rationale we can find is that the drafting team believes this is acceptable. No explanation for why this is acceptable was offered.
No
(1) We support shortening the voltage curve to four seconds to reflect the purpose of the standard to ride through voltage excursions which covers a transient time period. Furthermore, it reflects that the future PRC-025 will focus on steady state voltage limits. (2) We do not believe it is necessary to raise the performance bar for this standard by lowering the lower voltage curve to match the 0.85 pu voltage that is proposed to apply in the future PRC-025. First, having a requirement to ride through a voltage excursion to 0.9 pu for four seconds does not represent a conflict with PRC-025. It is simply less stringent than PRC-025. If PRC-025 requires more stringent performance using 0.85 pu for steady-state, that value can be set in that standard. Matching the proposed 0.85 pu in the proposed PRC-025 presumes that this is what the ultimate outcome of the PRC-025 standard will be. If PRC-025 were to end up with a 0.9 pu voltage requirement in the standard, then the standards again would not match. Second, no technical justification for changing the lower voltage ride through curve to 0.85 pu has been provided. If there is no technical justification to make the curve more stringent, it should not be made more stringent to simply match another proposed standard. Third, the overlap of the standards has been removed by striking load-affective protection functions such as impedance relays and voltage controlled overcurrent relays from this proposed PRC-024. How does the conflict in voltage performance exist when the standards apply to different equipment types? The load-affective protection will not be covered in proposed PRC-025 and will focus on steady-state conditions whereas the PRC-024 will focus on voltage excursions which are transient in nature and will apply to non-load affective protection performance.
Yes
(1) The data retention period is too long and is not consistent with the "Change State Element Paper No. 3 – Establish Compliance Data Requirements" whitepaper that NERC recently published as part of the reliability assurance initiative (RAI). It states that the retention period is the longer of three years or until the next audit. In effect, this makes the data retention period approximately six years since GOs are on a six year audit cycle. We believe this is simply too long a data retention period to demonstrate compliance and potentially refocuses audits on backwards looking changes that have no impact to reliability. Consider a generator

that may undergo multiple setting changes. Is it necessary to retain all setting changes over this period or only the most recent ones that indicate the generator is currently set to ride through voltage and frequency excursions? Retaining historical settings that have been changed does nothing to support reliability and only perpetuates the paper driven compliance culture rather than a culture of reliability. (2) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls, entity impact evaluation, and elimination of zero-defect expectations). The VSLs for Requirements R1 and R2 could be read to require self-reporting of every unit that tripped for a voltage or frequency excursion inside the no trip zone. To refocus NERC efforts on compliance, the recent reliability assurance initiative would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. These approaches are being written into the standards (CIP, COM-003, etc.). We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this standard. (3) Because the voltage envelope is based on assumptions listed on page 19, the VSLs for R1 and R2 need to clarify that if a unit does trip in the no trip zone and the actual system conditions do not match these assumptions that the trip does not represent a violation. For instance, if a synchronous condenser or capacitor (bullet 2 under “Evaluating Protective Relay Settings” on page 19) is not available that was assumed to be available when evaluating protection relay settings, why would the GO be held accountable for its unit tripping during a voltage excursion? It followed the assumptions set out in the standard. (4) The response to our previous comments that requirement R3 and R5 are the types of requirements the Project 2013-02 Paragraph 81 drafting team is proposing to eliminate indicated that they do not meet criteria A. This implies that these requirements do provide significant reliability support. However, no justification for how they provide significant reliability support was provided. Please explain how a requirement such as R3 that requires documentation and communication supports reliability. Requirement R1 already allows a GO an exception for documented and communicated equipment limitations. Because compliance is driven by evidence, the GO would have to document the limitation and communicate the limitation per the third bullet in Requirement R1. A separate requirement is simply not needed and “does little, if anything, to benefit or protect the reliable operation of the BES” above and beyond Requirement R1. The VSLs even seem to support this position since they focus primarily on the number of days late a registered entity has performed the task. Any further need to communicate the limitations could be rolled into the third bullet of Requirement R1. Requirement R5 is similarly situated requirement. Please explain how this requirement provides significant reliability support and, thus, does not meet criterion A. While we agree that generator protection settings changes need to be communicated, we simply do not see how a specific requirement to communicate them supports reliability. A requirement is not needed for every single task that should be completed. The requirement continues to perpetuate the paper driven compliance approach that NERC has recognized needs to change and is in the process of changing. If the drafting team believes, the requirement is still needed, we suggest including it as part of requirements R1 and R2.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Associated Electric Cooperative, Inc. - NCR01177
Yes
Yes
Yes
Yes
AECI appreciates this SDT’s demonstrated attention to industry feedback. Draft 5 PRC-024 R1 Bullet 3, COMMENT: AECI appreciates this “catch-all” being in there, and we hope it is worded to adequately cover any other technically justifiable plant relay settings the SDT failed to mention, that intentionally operate within the industry’s Attachment 1 No Trip zones. However we are concerned that R1’s and Bullet #3’s collective wording may specifically exclude any other protective relay settings outside of Bullet #1 and Bullet #2, including those specifically designed for other plant equipment limitations. (R2 Bullets #3 & #4 seem to provide better flexibility for what we failed to think of in this draft 5.) Draft 5 PRC-024 page 14, Attachment 1, Curve Data Points:, Eastern Interconnection, COMMENT: It just seems that even without a fluxuating frequency profile, the Eastern Interconnection’s frequency-bounded curves, functionally-declared within that table’s middle-row, can make a calculation for compliance with Requirements R1 & R4 a bit challenging. (Page 17’s first bullet#3, providing clarity around evaluating step-wise voltage excursions, provided some insight into what is currently drafted for Requirements R1 and R4 in conjunction with Attachment 1, where these continuous Eastern Interconnection curves are in play, and actual plant performance studies and results are analyzed.) While we expect to evaluate plant performance only around our known discrete plant relay settings, we are a bit concerned for the way this Standard’s non-discrete duration-functions might be leveraged against the industry when actual events occur. Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-Through Curve Clarifications, Curve Details:, Bullet3:, REPLACE: “voltage exceeds", WITH: “voltage first exceeds”, RATIONALE: Further clarity as to why duration is only 0.1 seconds in this example. Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-through Curve Clarifications, Curve Details:, Bullet4:, REPLACE: “proportion to deviations of frequency below normal ”, WITH: “proportion to below-normal deviations within the provided frequency profile", RATIONALE: Clarity that adjustment is made for study-related frequency profiles provided in conjunction with a request, and not for immediately experienced voltage deviations as they occur. Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-Through Curve Clarifications, Evaluating Protective Relay Settings:, Bullet 1.c. REPLACE: “terminals).”, WITH: “terminals.”, RATIONALE: Balanced parentheticals
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes

Yes
Yes
Yes
The 60 calendar day requirement in Requirement 5 for a Generator Owner to respond to a written request from its Transmission Planner or Planning Coordinator for generator protection trip settings, is too long. Because of the critical nature of this information, prolonging assessing system coordination can result in an unnecessary risk to the reliability of the Bulk Electric System. Oncor requests that this time requirement be shortened to 30 days.
Individual
Alice IReland
Xcel Energy
Yes
Yes
Yes
(1) We agree with the changes made to the Voltage Ride Through Curve in Attachment 2. However, we note that the Curve Data Points table in Attachment 2 does not reflect corresponding updates, thus producing inconsistency between the graphic and tabular voltage ride through specifications. Please reconcile the differences to make both specifications consistent. (2) Suggest adding the prefix “POI” to the graph title such that it reads “ POI Voltage Ride-Through….” – adding the prefix makes it explicitly clear that the curve does not apply to the generator terminal voltage. This clear distinction is important to eliminate potential confusion since the relay loadability options in PRC-025 allow using either POI voltage (85%) or generator terminal voltage (95%). (3) Suggest enhancing the verbiage in the text-box in the voltage ride-through curve as follows to clarify that it applies to continuous operation and using “system adjustments” instead of “changes to the system”. Suggested verbiage is: “Voltage for continuous operation (> 600 seconds) will be restored between 0.95 pu and 1.05 pu by automatic and/or manual system adjustments”.
Yes
(1) It is not apparent why the verbiage preceding and following the parenthetical text in Footnote 1 – that is, “Each GO is not required to have frequency or voltage protective relaying installed or activated on its unit.” – Is essential. This applicability exclusion is sufficiently clear in the verbiage of the requirements R1 and R2, which states “Each GO that has generator protective relaying activated to trip its generating unit(s)…”. Can a GO possibly activate a protective relay that is not installed? Therefore it seems redundant to include the applicability exclusion in the footnote and we suggest omitting it. (2) Suggest simplifying Footnote 1 as follows by retaining only the parenthetical text since it sufficiently captures the footnote’s primary intent --- suggested footnote text is “ 1 Including but not limited to frequency and voltage protective functions….….. to the generator based on frequency or voltage inputs.”
Suggest improving consistency between R1 and R2 verbiage by addressing the following editorial comments: (a) Not sure why the qualifying phrase “… as a result of voltage excursion (at the point of interconnection)…” is used in R2 but no corresponding qualification is used in R1? If this specificity for voltage excursion is needed in R2, then shouldn’t it also be needed for frequency excursions in R1? (b) Re-order the bulleted exceptions under R1 and R2 such that they appear in the same sequence in both requirements – this will make it easier for the uninitiated reader to observe that R1 and R2 share 3 common exceptions and R2 has one additional exception. (c) Readability and comprehension of R2 will be significantly enhanced if it is simplified by splitting it into 2 or more shorter sentences. Its existing structure – a very long, compound sentence of more than 100 words – is not conducive to easy comprehension and is prone to ambiguities in interpretation, leading to compliance confusion. (d) R1 states “Each GO…. shall set <such> protective relaying <so> that the…. does not <operate to> trip” whereas R2 states “Each GO….. shall set <its> protective relaying <such> that the…. does not trip”. It is hard to detect any good reason for the choice of words <such> and <so> in R1 versus <its> and <such> in R2, or for choosing to say <operate to> trip in R1 versus omitting that phrase in R2. Suggest identical lead-in sentences unless there is a good reason for the variations.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Russell Noble
Cowlitz PUD
No
Cowlitz agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected given a PC or TP excursion profile. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority. Again Cowlitz points out that engineering staff is not available for small entities and must be contracted. Since the Standard does not limit the PC and TP on the severity of the excursion profile that can be submitted to the GO for a time duration estimate, there is no possible way to prepare for a worst case scenario. The Standard does not allow for the GO to negotiate a more reasonable time frame to submit a response to the requesting entity, and as such places undue burden on the GO to solicit contractor/consultant services in a short time frame. Further, the statement “sound engineering judgment” is

subjective and open to much question as to when compliance has been achieved. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted, or at the very least allow for engineering judgment (without "sound") and limit the excursion profile to cover generators operating under the exception provisions of the Standard. Further, the Standard should allow the requestors to judge responses as adequate or not, and if not satisfied request further substantiating evidence that is reasonable.
Yes
Yes
Yes
Cowlitz also recommends Footnote 1 be clarified concerning the expression "…protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs." It is unclear whether or not this statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. Cowlitz suggests a change to "…protective functions within control systems specifically programmed to provide frequency or voltage protection trip points…" This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation…including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
(A) Confusion is created by making exemptions, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such "protective relays" meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% over speed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, "Excludes limitations that are caused by the generator frequency and voltage protective relays themselves." Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed.******(B) The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn't be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor mass flow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available.******(C) Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation.******(D) The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Generator Verification Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the proposed revisions to PRC-024-1. This standard was posted for a 30-day public comment period from December 12, 2012 through January 11, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 49 sets of comments, including comments from approximately 143 different people from approximately 98 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration: The vast majority of stakeholders agreed with the removal of R5 from the standard. Several stakeholders suggested that there were issues with R4. These commenters pointed out that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as "sound engineering judgment" is subject to interpretation and vague. Based on these comments, the GVSDT removed R4 from the standard. PRC-024-1 is now a relay setting standard.

Minority issue: Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard. The proposed draft of PRC-024 does not accomplish this. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection Agreements and not NERC Standards.

A large majority of stakeholders agreed with the change made to Attachment 1. Some stakeholders questioned the potential impact this change might make due to the elimination of the margin between the allowable UFLS overshoot and the generator overfrequency trip setpoints. The GVSDT pointed out that setting overfrequency tripping at this point would be allowed under the previous curve as a technically-based exemption under Requirement R3 and the change made removes a conflict with internationally-recognized technical standards.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Most stakeholders agreed with the revisions to the voltage ride-through curves in Attachment 2. Several stakeholders had concerns with the low voltage ride-through criteria being lowered to 85% for the 3-4 second interval. Stakeholders pointed out that transmission systems are designed to operate between 90% to 110% and not down to 85% and as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. The GVSDT agrees with these comments and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The majority of comments expressed agreement with the removal of loadability relays from PRC-024. One commentator recommended that the Generator Relay Loadability drafting team vet the removal of these relay types from Footnote 1. The GVSDT had previous discussions with that drafting team and they concurred with the revision to PRC-024.

Stakeholders provided valuable input regarding suggested improvements to language within the standard. Based on these comments, the following improvements were made to the draft standard:

- Removed Requirement R4 from the standard because of ambiguous language and limited reliability benefit.
- Revised the title of the standard to “Generator Frequency and Voltage Protective Relay Settings” and the Purpose Statement to “Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
- Revised “generating unit(s)” to “applicable generating unit(s)” to reflect that the standard only applies to units that meet the registry criteria.
- Added “regulatory or” language regarding limitations to reflect that NERC, environmental or regulatory requirements may cause a limitation in generator performance.
- Revised Requirement R2 so that the sentences were shorter and easier to read, and made conforming language changes in Requirement R1.
- Removed the last bullet from Requirement R3 and added a new bullet referencing frequency impacts on turbines as follows: “Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.”
- Revised Requirement R5 (now R4) to indicate that the trip settings to be provided are only those “associated with Requirements R1 and R2” and not all relays.
- Revised the measures based on requirement revisions.
- Updated the VSLs for R3 and R4 to allow 30 day increments between levels rather than the original 10 days. This comports with other standards developed under this project.
- Updated the table in Attachment 2 (this was missed in the previous revision).

- Made clarifying revisions to "Voltage Ride-Through Curve Clarifications" on the last page of the standard.
- Clarified Footnote 3 to: "Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."

Index to Questions, Comments, and Responses

Table of Contents

1. The GVSDT has removed Requirement R5 from the standard. The standard drafting team believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. Do you agree with this revision? If not, please explain in the comment area below. 13
2. Several stakeholders pointed out that a portion of the allowable high frequency trip curve for the Eastern, ERCOT, and Quebec Interconnections (Attachment 1) exceeded the off-nominal frequency limits in IEEE C50.13 and IEC 60034 that are used by equipment manufacturers to design generators. The drafting team revised the high frequency portion of the curve from zero to two seconds for the Eastern and ERCOT Interconnections to meet the IEEE and IEC standards. This leaves no margin between the high frequency allowance for UFLS designers in frequency overshoot for that amount of time, but the drafting team feels this is acceptable. Do you agree with this change? If not, please provide specific suggestions for change in the comment area. 22
3. In the previous draft of this standard the voltage ride-through curves in Attachment 2 extended out for 600 seconds before returning to normal operating voltages (95% – 105% of nominal). Also, the final step in the low voltage recovery curve was at 90% of nominal after three seconds. Commenters to the Generator Relay Loadability project pointed out that this could potentially cause conflicts with coordination of settings for relay loadability, since they need to be evaluated for stressed system conditions of voltages at 85% of nominal. In response, the drafting team has moved the final step of the low voltage recovery curve down from 90% to 85% at three seconds and has shortened the curves so that they end at four seconds. The drafting team believes this clarifies the intent of this standard to address the transient conditions without conflicting with relay loadability. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area. 27
4. Footnote 1 has been revised to remove reference to impedance relays and voltage controlled overcurrent relays which are load-affected protective functions. This was done to remove overlap and potential conflict of coordination with the Generator Relay Loadability project. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area. 34
5. Do you have any other comment, not expressed in questions above, for the GVSDT?.................. 41

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11. Christina Koncz	PSEG Power LLC	NPCC	5
12. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13. Bruce Metruck	New York Power Authority	NPCC	6
14. Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16. Robert Pellegrini	The United Illuminating Company	NPCC	1
17. Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19. Brian Robinson	Utility Services	NPCC	8
20. Brian Shanahan	National Grid	NPCC	1
21. Wayne Sipperly	New York Power Authority	NPCC	5
22. Donald Weaver	New Brunswick System Operator	NPCC	2
23. Ben Wu	Orange and Rockland Utilities	NPCC	1
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

2.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Group	X	X	X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jonathan Hayes	Southwest Power Pool	SPP	NA
2. Robert Rhodes	Southwest Power Pool	SPP	NA
3. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4. Don Taylor	Westar Energy	SPP	1, 3, 5, 6
5. Stephen McGie	City of Coffeyville	SPP	NA
6. Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
7. Mike Sheriff	Oklahoma Gas and Electric Company	SPP	1, 3, 5
8. Harold Wyble	Kansas City Power and Light	SPP	1, 3, 5, 6

3.	Group	Charles Yeung	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Greg Campoli	NYISO	NPCC	2
2. Bill Phillips	MISO	MRO	2
3. Ben Li	IESO	NPCC	2
4. Steve Myers	ERCOT	ERCOT	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Matt Goldberg	ISONE	NPCC	2										
6. Tom Bowe	PJM	RFC	2										
4.	Group	paul haase	seattle city light	X		X	X	X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. pawel krupa	seattle city light	WECC	1										
2. dana wheelock	seattle city light	WECC	3										
3. hao li	seattle city light	WECC	4										
4. mike haynes	seattle city light	WECC	5										
5. dennis sismaet	seattle city light	WECC	6										
5.	Group	Connie Lowe	Dominion	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Louis Slade		RFC	5, 6										
2. Randi Heise		MRO	5, 6										
3. Mike Garton		NPCC	5, 6										
4. Michael Crowley		SERC	1, 3, 5, 6										
6.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Ian Grant		SERC	3										
2. Marjorie Parsons		SERC	6										
3. David Thompson		SERC	5										
4. DeWayne Scott		SERC	1										
5. Tom Vandervort		SERC	5										
7.	Group	Greg Rowland	Duke Energy	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Doug Hils	Duke Energy	RFC	1										
2. Lee Schuster	Duke Energy	FRCC	3										
3. Dale Goodwine	Duke Energy	SERC	5										
4. Greg Cecil	Duke Energy	RFC	6										
8.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				
Additional Member	Additional Organization	Region	Segment Selection										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	TOM BREENE	WPS	MRO	3, 4, 5, 6
3.	JODI JENSON	WAPA	MRO	1, 6
4.	KEN GOLDSMITH	ALTW	MRO	4
5.	ALICE IRELAND	XCEL/NSP	MRO	1, 3, 5, 6
6.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
7.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
8.	JOE DEPOOTER	MGE	MRO	3, 4, 5, 6
9.	SCOTT NICKELS	RPU	MRO	4
10.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
11.	MARIE KNOX	MISO	MRO	2
12.	LEE KITTELSON	OTP	MRO	1, 3, 5
13.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
14.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
15.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
16.	DAN INMAN	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL Energy Plus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1. Stephen Hitchens	Technical Operations	WECC	1
2. Rebecca Berdahl	Policy Development & Analysis	WECC	3
3. James Burns	Technical Operations	WECC	1
4. Deanna Phillips	FERC Compliance	WECC	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Jason Marshall	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
2. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3. Megan Wagner	Sunflower Electric Power Corporation	SPP	1
4. Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
5. John Shaver	Southwest Transmission Cooperative	WECC	1
6. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
7. Tom Alban	Buckeye Power	RFC	3, 4
8. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Individual	Janet Smith	Arizona Public Service Company	X		X	X	X	X	X			
14.	Individual	ryan millard	pacificorp	X		X		X	X				
15.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
16.	Individual	Bill Shultz	Southern Company	X		X		X	X				
17.	Individual	Ken Gardner	Alberta Electric System Operator		X								
18.	Individual	John Bee	Exelon Corporation and its affiliates	X		X	X	X	X				
19.	Individual	Jim Keller	We Energies			X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Patrick Brown	Essential Power, LLC					X					
21.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
22.	Individual	Michelle DAntuono	Ingleside Cogeneration LP					X					
23.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
24.	Individual	David Jendras	Ameren	X		X		X	X				
25.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
26.	Individual	Jonathan	Appelbaum	X									
27.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
28.	Individual	Anthony Jablonski	ReliabilityFirst										X
29.	Individual	Michelle Clements	Wolverine Power Supply Cooperative, Inc.	X									
30.	Individual	Kathleen Goodman	ISO New England Inc.		X								
31.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
32.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
33.	Individual	Thad Ness	American Electric Power	X		X		X	X				
34.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
35.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
36.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X		X	X				
37.	Individual	Scott Kinney	Avista	X									
38.	Individual	Mike Hendrix	Idaho Power Company	X									
39.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
40.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
41.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
42.	Individual	Michael Falvo	Independent Electricity System Operator		X	X	X	X					
43.	Individual	Joylyn Faust	Consumers Energy Company										
44.	Individual	Michael Goggin	American Wind Energy Association								X		
45.	Individual	Brad Harris	CenterPoint Energy	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
46.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
47.	Individual	Alice IReland	Xcel Energy	X		X		X	X				
48.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
49.	Individual	Russell Noble	Cowlitz PUD			X	X	X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of “Entity Name”
Brazos Electric Power Cooperative, Inc.	Agree	ACES Power Marketing
US Army Corps of Engineers	Agree	MRO NSRF
Alliant Energy	Agree	MRO NSRF

1. **The GVSDT has removed Requirement R5 from the standard. The standard drafting team believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of stakeholders agreed with the removal of R5 from the standard. Several stakeholders suggested that there were issues with R4. These commenters pointed out that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as "sound engineering judgment" is subject to interpretation and vague. Based on these comments, the GVSDT removed R4 from the standard. PRC-024-1 is now a relay setting standard.

Minority issue: Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard. The proposed draft of PRC-024 does not accomplish this. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection Agreements and not NERC Standards.

Organization	Yes or No	Question 1 Comment
Tennessee Valley Authority	No	Recommend that the R4 be enhanced to give more detail on how to satisfy this requirement. As significant as R4 is, the Generator Owners need more guidance than what is currently stated.
Response: The GVSDT thanks you for your comment. Based on industry input the GVSDT has removed Requirement R4 from the standard. The standard drafting team believes that Requirement R3 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to provide an estimate of the time duration the generating unit(s) will remain connected if the unit(s) was to experience a frequency or voltage excursion would not justify the resulting incremental gain in grid reliability.		
PPL Corporation NERC Registered Affiliates	No	Although PPL Companies agree with the removal of R5, PPL is still concerned with the following criteria stated in R4. R4 allows using,

Organization	Yes or No	Question 1 Comment
		“experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis we could make regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit in the fleet, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance. For R4 to reach this goal we believe that PRC-024 Measure 4 should state that “No concrete data on which to base judgments - assume tripping,” is an acceptable measure for R4.
Response: The GVSDT thanks you for your comment. Based on industry input the GVSDT has removed Requirement R4 from the standard. The standard drafting team believes that Requirement R3 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to provide an estimate of the time duration the generating unit(s) will remain connected if the unit(s) was to experience a frequency or voltage excursion would not justify the resulting incremental gain in grid reliability.		
Alberta Electric System Operator	No	The AESO disagrees with this requirement being removed from Draft 5 and believes that new generating must be required to be designed, built and maintained in compliance with PRC-024-1 unless it is due to equipment failure and in such cases the owner of the generating unit must report

Organization	Yes or No	Question 1 Comment
		failure to the ISO with a plan to address the failure.
Response: The GVSDT thanks you for your comment. While the GVSDT understands your concern, the team has decided that inclusion of a plant performance requirement in a relay setting standard is inappropriate.		
We Energies	No	The NAGF agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using, "experience, actual event histories, or sound engineering judgment," to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word "sound" implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, "Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered," (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that "No concrete data on which to base judgments - assume tripping," is an acceptable response.
Essential Power, LLC	No	We agree with the removal of R5, but am still concerned with the criteria stated in R4. R4 allows using, "experience, actual event histories, or sound engineering judgment," to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not

Organization	Yes or No	Question 1 Comment
		required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that “No concrete data on which to base judgments - assume tripping,” is an acceptable response.
Cogentrix Energy Power Management, LLC	No	The NAGF agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,”

Organization	Yes or No	Question 1 Comment
		(the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that “No concrete data on which to base judgments - assume tripping,” is an acceptable response.
Cowlitz PUD	No	Cowlitz agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected given a PC or TP excursion profile. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority. Again Cowlitz points out that engineering staff is not available for small entities and must be contracted. Since the Standard does not limit the PC and TP on the severity of the excursion profile that can be submitted to the GO for a time duration estimate, there is no possible way to prepare for a worst case scenario. The Standard does not allow for the GO to negotiate a more reasonable time frame to submit a response to the requesting entity, and as such places undue burden on the GO to solicit contractor/consultant services in a short time frame. Further, the statement “sound engineering judgment” is subjective and open to much question as to when compliance has been achieved. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted, or at the very least allow for engineering judgment (without “sound”) and limit the excursion profile to cover generators operating under the exception provisions of the Standard. Further, the Standard should allow the requestors to judge responses as adequate or not, and if not satisfied

Organization	Yes or No	Question 1 Comment
		request further substantiating evidence that is reasonable.
Response: The GVSDT thanks you for your comments. Based on industry input the GVSDT has removed Requirement R4 from the standard. The standard drafting team believes that Requirement R3 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to provide an estimate of the time duration the generating unit(s) will remain connected if the unit(s) was to experience a frequency or voltage excursion would not justify the resulting incremental gain in grid reliability.		
American Wind Energy Association	No	AWEA does not support this revision, but does not wish to hold up the standards development process for PRC-024. AWEA strongly supported keeping the standard as a generator performance standard, believing that the standard would result in improved electric reliability. AWEA also supports NERC taking the lead in setting national reliability standards, instead of the far less efficient outcome of individual regions advancing their own reliability standards. Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard.
Response: The GVSDT thanks you for your comment and support of this standard development process. The team has decided that inclusion of a plant performance requirement in a relay setting standard is inappropriate. This proposed standard is consistent across technologies in that it does not impose voltage or frequency ride through requirements on any generators. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection Agreements and not NERC Standards.		
CenterPoint Energy	No	CenterPoint Energy previously expressed concern that the proposed standard does not impose any minimum frequency or voltage ride-through requirements for existing generating stations. With this proposed revision, the standard will not even impose any minimum requirements for new generating stations. Failure of a generating unit to ride-through at least

Organization	Yes or No	Question 1 Comment
		some minimum threshold of frequency and voltage excursions places the reliability burden solely on transmission entities. This makes is difficult to compensate for the generator's failure to perform and, therefore, is problematic for BES reliability.
Response: The GVSDT thanks you for your comment and understands your concern. The team has decided that inclusion of a plant performance requirement in a relay setting standard is inappropriate.		
ACES Standards Collaborators	Yes	Thank you for making this change.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP is firmly in agreement with the removal of the ride-through performance requirement (R5) from PRC-024-1. Although we understand the intent to guarantee generation availability for a set of voltage and frequency transients, the project team has correctly determined that the costs far outweigh the benefits. In our view, this is in keeping with the spirit of the Cost Effective Analysis Process, Paragraph 81, and other risk-based compliance initiatives that were initiated to maintain that careful balance.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group	Yes	
IRC Standards Review Committee	Yes	
Dominion	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
pacificorp	Yes	
Salt River Project	Yes	
Southern Company	Yes	
Cleco	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	
Tacoma Power	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
ISO New England Inc.	Yes	
Entergy Services, Inc. (Transmission)	Yes	

Organization	Yes or No	Question 1 Comment
Liberty Electric Power LLC	Yes	
American Electric Power	Yes	
Manitoba Hydro	Yes	
Sacramento Municipal Utility District	Yes	
Avista	Yes	
Kansas City Power & Light	Yes	
Oncor Electric Delivery Company LLC	Yes	
Xcel Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The standard has been modified to provide 30 days increments between VSL levels as requested.		

2. **Several stakeholders pointed out that a portion of the allowable high frequency trip curve for the Eastern, ERCOT, and Quebec Interconnections (Attachment 1) exceeded the off-nominal frequency limits in IEEE C50.13 and IEC 60034 that are used by equipment manufacturers to design generators. The drafting team revised the high frequency portion of the curve from zero to two seconds for the Eastern and ERCOT Interconnections to meet the IEEE and IEC standards. This leaves no margin between the high frequency allowance for UFLS designers in frequency overshoot for that amount of time, but the drafting team feels this is acceptable. Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: A large majority of stakeholders agreed with the change made to Attachment 1. Some stakeholders questioned the potential impact this change might make due to the elimination of the margin between the allowable UFLS overshoot and the generator overfrequency trip setpoints. The GVSDT pointed out that setting overfrequency tripping at this point would be allowed under the previous curve as a technically-based exemption under Requirement R3 and the change made removes a conflict with internationally-recognized technical standards.

Organization	Yes or No	Question 2 Comment
Southwest Power Pool Reliability Standards Development Group	No	Our concern is by eliminating the instantaneous high frequency overshoot margin that you could cause an unintended cascading event on the system. For example when you drop load it could cause an instantaneous unit trip, due to instantaneous high frequency on the unit, which would then cause an under frequency load trip. We would suggest that the drafting team let the regions investigate before approving this reduction in the margin for this time period and standard as a whole.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards.		
IRC Standards Review	No	We are concerned about how this change may impact the how the system responds

Organization	Yes or No	Question 2 Comment
Committee		to frequency excursions. Please refer to our comment in question 5.
Response: The GVSDT thanks you for your comment. Please see the response to your comment in Question 5.		
ACES Standards Collaborators	No	While we are not opposed to this change per se and do not offer any suggested alternatives, we would like to see a technical justification for why this is acceptable. The only rationale we can find is that the drafting team believes this is acceptable. No explanation for why this is acceptable was offered.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards.		
Independent Electricity System Operator	No	This should be confirmed with the UFLS designers in conjunction with PRC-006 and PRC-006-NPCC to see how this is coordinated with the frequency overshoot for that amount of time.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. This allowance has been in all drafts of the PRC-024 standard, so the UFLS designers should already have been aware of the possibility. Several regions already recognized the limitation created by the IEEE and IEC standards and have already adjusted their UFLS program requirements accordingly. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards. In the event a particular region believes the IEEE and IEC limits are unworkable, a more restrictive regional standard may be written to address the issue, but the GVSDT does not feel it is wise to mandate this across the continent.		
PPL Corporation NERC Registered Affiliates	No	

Organization	Yes or No	Question 2 Comment
ISO New England Inc.	No	
MRO NSRF	Yes	Could the drafting team please clarify the risk to the BES by leaving no margin for frequency overshoot? The NSRF was unsure if reducing the no trip margin above the IEEE / IEC design limits really represented a reliability risk to the BES. If generator units do overshoot the IEEE / IEC curve and remain on-line without damage, that doesn't appear to be a reliability risk. If the generator should trip to avoid damage from a frequency overshoot above the IEEE / IEC curve for which the unit was designed, that would also appear to be better for reliability, even if the unit does trip.
Response: The GVSDT thanks you for your comment. The potential risk would be to an area that may island with more generation than load (due to the configuration of the initial separation or due to load shedding) causing the frequency to rise. UFLS designers are supposed to limit the frequency overshoot to 61.8 Hz. Generators with overfrequency protection set to that value may trip, causing frequency to drop more dramatically than expected due to governor action. The GVSDT agrees with your assessment that preventing damage to generating equipment does improve reliability.		
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
pacificorp	Yes	

Organization	Yes or No	Question 2 Comment
Salt River Project	Yes	
Southern Company	Yes	
We Energies	Yes	
Essential Power, LLC	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Entergy Services, Inc. (Transmission)	Yes	
American Electric Power	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
Oncor Electric Delivery Company LLC	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
Cowlitz PUD	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has changed the time increment to 30 days in the VSL's for Requirements R3 and R4 (previously R5). Requirement R4 from Draft 5 has been removed.		

3. **In the previous draft of this standard the voltage ride-through curves in Attachment 2 extended out for 600 seconds before returning to normal operating voltages (95% – 105% of nominal). Also, the final step in the low voltage recovery curve was at 90% of nominal after three seconds. Commenters to the Generator Relay Loadability project pointed out that this could potentially cause conflicts with coordination of settings for relay loadability, since they need to be evaluated for stressed system conditions of voltages at 85% of nominal. In response, the drafting team has moved the final step of the low voltage recovery curve down from 90% to 85% at three seconds and has shortened the curves so that they end at four seconds. The drafting team believes this clarifies the intent of this standard to address the transient conditions without conflicting with relay loadability. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: Most stakeholders agreed with the revisions to the voltage ride-through curves in Attachment 2. Several stakeholders had concerns with the low voltage ride-through criteria being lowered to 85% for the 3-4 second interval. Stakeholders pointed out that transmission systems are designed to operate between 90% to 110% and not down to 85% and as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. The GVSDT agrees with these comments and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator).

Organization	Yes or No	Question 3 Comment
Southwest Power Pool Reliability Standards Development Group	No	We would like to see consistency between the voltage ride through curve and the off nominal frequency capability curve in the log scale. The last draft was consistent and we wonder why the drafting team changed the voltage ride through curve to a linear depiction?
Response: The GVSDT thanks you for your comment. The SDT believes that since the voltage curves were shortened to 4 seconds to address the transient conditions without conflicting with relay loadability, a linear depiction is adequate.		
ACES Standards Collaborators	No	(1) We support shortening the voltage curve to four seconds to reflect the purpose of the standard to ride through voltage excursions which covers a transient time

Organization	Yes or No	Question 3 Comment
		period. Furthermore, it reflects that the future PRC-025 will focus on steady state voltage limits. (2) We do not believe it is necessary to raise the performance bar for this standard by lowering the lower voltage curve to match the 0.85 pu voltage that is proposed to apply in the future PRC-025. First, having a requirement to ride through a voltage excursion to 0.9 pu for four seconds does not represent a conflict with PRC-025. It is simply less stringent than PRC-025. If PRC-025 requires more stringent performance using 0.85 pu for steady-state, that value can be set in that standard. Matching the proposed 0.85 pu in the proposed PRC-025 presumes that this is what the ultimate outcome of the PRC-025 standard will be. If PRC-025 were to end up with a 0.9 pu voltage requirement in the standard, then the standards again would not match. Second, no technical justification for changing the lower voltage ride through curve to 0.85 pu has been provided. If there is no technical justification to make the curve more stringent, it should not be made more stringent to simply match another proposed standard. Third, the overlap of the standards has been removed by striking load-affective protection functions such as impedance relays and voltage controlled overcurrent relays from this proposed PRC-024. How does the conflict in voltage performance exist when the standards apply to different equipment types? The load-affective protection will not be covered in proposed PRC-025 and will focus on steady-state conditions whereas the PRC-024 will focus on voltage excursions which are transient in nature and will apply to non-load affective protection performance.
Response: The GVSDT thanks you for your comment. In response to part 2 of the comment, The SDT agrees with your comment and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator).		
Alberta Electric System Operator	No	The AESO disagrees with the use of 85% and supports the values as expressed previously in draft 4 of PRC-024-1. Transmission systems are designed to operate

Organization	Yes or No	Question 3 Comment
		between 90% to 110% and not down to 85%, as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. In particular, as NERC has left the 85% duration open ended, it is unclear how long a generating unit is to remain on-line under this condition. In addition, there appears to be a discrepancy in Attachment 2 where the "Curve Data Points" table identify a low voltage ride through duration of 600 seconds for <0.90 pu voltage and the "Voltage Ride Through Time Duration Curve" shows this to occur <0.85 pu voltage. Based on the explanation above, the table should be updated accordingly.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comment and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The Voltage Ride-Through Time Duration Table has been updated.		
CenterPoint Energy	No	CenterPoint Energy agrees with lowering the low voltage recovery curve down from 90% to 85% at three seconds; however, CenterPoint Energy is concerned with truncating the curves at 4 seconds due to undervoltage load shedding (UVLS) and relay loadability factors. For coordination with UVLS systems, CenterPoint Energy recommends the curve be extended to at least 10 seconds. Additionally, the purpose of relay loadability standards is to allow sufficient time for system operators to take corrective actions. Based on the purpose of relay loadability, CenterPoint Energy believes the curves should remain extended through 600 seconds.
Response: The GVSDT thanks you for your comment. Based on other industry comments, the chart has been returned to the 90% level found in the previous draft. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The SDT shortened the voltage curves to 4 seconds to address the transient conditions without conflicting with relay loadability standards. The Voltage Ride-Through Time Duration Table has been updated.		

Organization	Yes or No	Question 3 Comment
Consumers Energy Company	No	
Northeast Power Coordinating Council	Yes	The Curve Data Points table on page 18 of Draft 5 has not been updated to reflect the changes mentioned above.
Response: The GVSDT thanks you for your comment. The "curve data points" table of Attachment 2 has been corrected.		
Dominion	Yes	Draft 5 Page 16 (clean version) the Curve Data Points table has not been updated to reflect the changes mentioned in question #3 above. Dominion agrees with the changes provide this modification is made.
Response: The GVSDT thanks you for your comment. The "curve data points" table of Attachment 2 has been corrected.		
ISO New England Inc.	Yes	The curve data points chart was not revised when the drawing (including timescale) was revised. This leads to confusion however overall the change shown in the curve to 0.85 is acceptable.
Response: The GVSDT thanks you for your comment. The "curve data points" table of Attachment 2 has been corrected.		
MRO NSRF	Yes	The NERC generator relay loadability standards don't appear to state times, so changing the curves from 600 seconds to 3 and 4 seconds is a step in the right direction but could still lead to conflicts unless this standard or PRC-025 is amended. In a relay world that typically operates in cycles, 3 to 4 seconds is still a very long time and the NSRF believes that conflicts are still possible unless both standards are coordinated carefully. It is inappropriate to force entities to choose which standard to potentially violate. Please make sure that the associated graphs and curves data points within the table match each other.
Response: The GVSDT thanks you for your comment. Based on other industry comments, the chart has been returned to the 90% level found in the previous draft. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and		

Organization	Yes or No	Question 3 Comment
generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The SDT shortened the voltage curves to 4 seconds to address the transient conditions without conflicting with relay loadability standards. The curve data points table of Attachment 2 has been corrected.		
Xcel Energy	Yes	(1) We agree with the changes made to the Voltage Ride Through Curve in Attachment 2. However, we note that the Curve Data Points table in Attachment 2 does not reflect corresponding updates, thus producing inconsistency between the graphic and tabular voltage ride through specifications. Please reconcile the differences to make both specifications consistent. **The curve data points table of Attachment 2 has been corrected.** (2) Suggest adding the prefix "POI" to the graph title such that it reads " POI Voltage Ride-Through...." - adding the prefix makes it explicitly clear that the curve does not apply to the generator terminal voltage. This clear distinction is important to eliminate potential confusion since the relay loadability options in PRC-025 allow using either POI voltage (85%) or generator terminal voltage (95%). **The prefix "POI" is used on the percentage of voltage legend on the right hand side of the graph in Attachment 2, the SDT believes this is adequate.** (3) Suggest enhancing the verbiage in the text-box in the voltage ride-through curve as follows to clarify that it applies to continuous operation and using "system adjustments" instead of "changes to the system". Suggested verbiage is: "Voltage for continuous operation (> 600 seconds) will be restored between 0.95 pu and 1.05 pu by automatic and/or manual system adjustments". **The curve is limited to 4 seconds in time and the GVSDT has removed the text box in question from the curve because it is no longer applicable.**
Response: The GVSDT thanks you for your comment. Please see responses to the individual comments above.		
IRC Standards Review Committee	Yes	

Organization	Yes or No	Question 3 Comment
Duke Energy	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Bonneville Power Administration	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
pacificorp	Yes	
Salt River Project	Yes	
Southern Company	Yes	
We Energies	Yes	
Essential Power, LLC	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	
Tacoma Power	Yes	
Wolverine Power Supply	Yes	

Organization	Yes or No	Question 3 Comment
Cooperative, Inc.		
Entergy Services, Inc. (Transmission)	Yes	
American Electric Power	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery Company LLC	Yes	
Cowlitz PUD	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the requested revision to the VSLs.		

4. **Footnote 1 has been revised to remove reference to impedance relays and voltage controlled overcurrent relays which are load-affected protective functions. This was done to remove overlap and potential conflict of coordination with the Generator Relay Loadability project. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: The majority of comments were in agreement with the removal of loadability relays from PRC-024.

One commentator recommended that the Generator Relay Loadability drafting team vet the removal of these relay types from Footnote 1. The GVSDT had previous discussions with that drafting team and they concurred with the revision to PRC-024.

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	No	The standard clearly specifies in R1 and R2 that frequency and voltage relaying should not operate within "no trip zone". Footnote 1 should be completely removed since is only an incomplete list of the possible generator protections.
Response: The GVSDT thanks you for your comment. The footnote clarifies that a Generator Owner is not required to install frequency or voltage relaying as a result of this standard. The drafting team declines to remove Footnote 1 because it clarifies that generator relays or protective functions that have inputs of frequency and voltage are to be considered as part of PRC-024.		
CenterPoint Energy	No	CenterPoint Energy does not agree with removing references to impedance relays and voltage controlled overcurrent relays in Footnote 1, as we are concerned that there could be some differences between relay loadability and low voltage ride-through. Voltages at 85% of nominal and emergency current levels are used for calculating relay set points for relay loadability. For low voltage ride-through, impedance relays and voltage controlled overcurrent relays would need to be evaluated at voltage levels as low as 0% of nominal and at short circuit fault current levels. Instead of removing these relays from Footnote 1 at this late point in the development of PRC-024, CenterPoint Energy suggests that this be addressed by the SDT for PRC-025 Generator Relay Loadability. The PRC-025 SDT has the appropriate

Organization	Yes or No	Question 4 Comment
		subject matter expertise to fully vet whether these types of relays should be removed from PRC-024.
Response: The GVSDT thanks you for your comment. The drafting team discussed the loadability relays that were in PRC-024 with the PRC-025 drafting team before the recent posting. As a result of the discussion, it was agreed that PRC-025 would contain the necessary criteria for evaluating relay settings based on generator loading and field forcing along with 85% voltage at the point of interconnection. The voltage ride-through curve in PRC-024 has a voltage profile for voltage recovery after fault clearing and does not consider generator loading. The relay coordination draft standard (PRC-027) would take into consideration relay coordination between the Generator Owner and the Transmission Owner. Therefore, it was permissible to remove the loadability relays from PRC-024.		
PPL Corporation NERC Registered Affiliates	Yes	The PPL Companies also recommend the following changes to Footnote 1. The expression, “protective functions within control systems...based on frequency or voltage inputs,” should be replaced with, “control system frequency or voltage trip setpoints.” It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, “known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer’s advisory.” Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
We Energies	Yes	The NAGF also recommend the following changes to Footnote 1. The expression, “protective functions within control systems...based on frequency or voltage inputs,” should be replaced with, “control system frequency or voltage trip setpoints.” It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a,

Organization	Yes or No	Question 4 Comment
		"known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
Essential Power, LLC	Yes	We recommend the following changes to Footnote 1. The expression, "protective functions within control systems...based on frequency or voltage inputs," should be replaced with, "control system frequency or voltage trip setpoints." It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
Cowlitz PUD	Yes	Cowlitz also recommends Footnote 1 be clarified concerning the expression "...protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs." It is unclear whether or not this statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. Cowlitz suggests a change to "...protective functions within control systems specifically programmed to provide frequency or voltage protection trip points..." This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and

Organization	Yes or No	Question 4 Comment
		when every contactor in a plant will drop-out for example is not possible.
Cogentrix Energy Power Management, LLC	Yes	The NAGF also recommend the following changes to Footnote 1. The expression, “protective functions within control systems...based on frequency or voltage inputs,” should be replaced with, “control system frequency or voltage trip setpoints.” It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, “known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer’s advisory.” Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
Response: The GVSDT thanks you for your comment. The GVSDT had follow-up conversations with members of the NAGF and reached a consensus on dealing with this issue. The GVSDT has revised R3 by adding “relay setting” into the requirement for clarity as follows: **R3. Each Generator Owner shall document each known regulatory or equipment limitation that prevents an applicable generating unit from meeting the *relay setting* criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advisory.**		
Xcel Energy	Yes	(1) It is not apparent why the verbiage preceding and following the parenthetical text in Footnote 1 - that is, “Each GO is not required to have frequency or voltage protective relaying installed or activated on its unit.” - Is essential. This applicability exclusion is sufficiently clear in the verbiage of the requirements R1 and R2, which states “Each GO that has generator protective relaying activated to trip its generating unit(s)...”. Can a GO possibly activate a protective relay that is not installed? Therefore it seems redundant to include the applicability exclusion in the footnote and we suggest omitting it.

Organization	Yes or No	Question 4 Comment
		The footnote was intended to add clarity that a Generator Owner is not required to activate a protective function in a digital relay. For example, if a digital relay has an option to activate an under-voltage relay option and the Generator Owner elects to not use this function, this standard does not require the Generator Owner to activate and set it according to the ride through curve. (2) Suggest simplifying Footnote 1 as follows by retaining only the parenthetical text since it sufficiently captures the footnote's primary intent --- suggested footnote text is " 1 Including but not limited to frequency and voltage protective functions......... to the generator based on frequency or voltage inputs." **The footnote clarifies that a Generator Owner is not required to install frequency or voltage relaying as a result of this standard. The concept of "including but not limited to frequency and voltage protective functions" clarifies that the protection may be performed by a protective relay, or are protection options available inside a control system. The final portion of the sentence inside the parenthetical which states, "generator based on frequency or voltage inputs" defines whether the protective function is considered as part of the standard.**
Response: The GVSDT thanks you for your comment. See answers to your comments above.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group	Yes	
IRC Standards Review Committee	Yes	
Dominion	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
ACES Standards Collaborators	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
pacificorp	Yes	
Salt River Project	Yes	
Southern Company	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	
Tacoma Power	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
ISO New England Inc.	Yes	

Organization	Yes or No	Question 4 Comment
Entergy Services, Inc. (Transmission)	Yes	
Liberty Electric Power LLC	Yes	
American Electric Power	Yes	
Manitoba Hydro	Yes	
Kansas City Power & Light	Yes	
Oncor Electric Delivery Company LLC	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the requested revision to the VSLs.		

5. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

Summary Consideration: Stakeholders provided valuable input regarding suggested improvements to language within the standard. Based on these comments, the following improvements were made to the draft standard:

- Removed Requirement R4 from the standards because of ambiguous language and dubious reliability benefit.
- Revised the title of the standard to "Generator Frequency and Voltage Protective Relay Settings" and the Purpose Statement to "Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
- Revised "generating unit(s)" to "applicable generating unit(s)" to reflect that the standard only applies to units that meet the registry criteria.
- Added "regulatory or" language regarding limitations to reflect that NERC, environmental or regulatory requirements may cause a limitation in generator performance.
- Revised Requirement R2 so that the sentences were shorter and easier to read, and made conforming changes to Requirement R1.
- Removed the last bullet from Requirement R3 and added and new bullet referencing frequency impacts on turbines as follows: "Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance."
- Revised Requirement R5 (now R4) to indicate that the trip settings to be provided are only those "associated with Requirements R1 and R2" and not all relays.
- Revised the measures based on requirement revisions.
- Updated the VSLs for Requirements R3 and R4 to allow 30 day increments between levels rather than the original 10 days. This comports with other standards developed under this project.
- Updated the table in Attachment 2 (this was missed in the previous revision).
- Made clarifying revisions to "Voltage Ride-Through Curve Clarifications" on the last page of the standard.
- Clarified Footnote 3 to: "Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."

Organization	Yes or No	Question 5 Comment
Southern Company		1) Add the word "evidence" between "shall have" and "that" in M2 (to match the wording of M1). **The GVSDT agrees and has made the suggested revision.** 2) We believe that R4, due to the uncertainty of speculating the probability of the unit ride-thru/trip when exposed to transmission system voltage and frequency excursions described by Attachment 1 and Attachment 2, will not yield beneficial information in support of the BES reliability. **R4 has been removed from the standard.** 3) The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. **R5, Draft 5 (R4, Draft 6) has been modified to clarify this: R4: Each Generator Owner shall provide its generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner (that models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.** 4) Delete the word "nameplate" on item 1.b on the last page of the draft standard under "Evaluating Protective Relay Settings" for voltage excursions. The language "full real-power output" enables GOs to use the best "full load MW" values they have for their units for plant-specific studies. **Clarification #1 has been modified to allow flexibility in choosing the loading conditions for the unit under study. Please see the revision: Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions.**

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. Please see responses above.		
ACES Standards Collaborators		(1) The data retention period is too long and is not consistent with the "Change State Element Paper No. 3 - Establish Compliance Data Requirements" whitepaper that NERC recently published as part of the reliability assurance initiative (RAI). It states that the retention period is the longer of three years or until the next audit. In effect, this makes the data retention period approximately six years since GOs are on a six year audit cycle. We believe this is simply too long a data retention period to demonstrate compliance and potentially refocuses audits on backwards looking changes that have no impact to reliability. Consider a generator that may undergo multiple setting changes. Is it necessary to retain all setting changes over this period or only the most recent ones that indicate the generator is currently set to ride through voltage and frequency excursions? Retaining historical settings that have been changed does nothing to support reliability and only perpetuates the paper driven compliance culture rather than a culture of reliability. **The GVSDT has used the boilerplate language provided by NERC Staff that is approved for use in standards. The whitepaper that you cite has not been approved for implementation. Auditors are still going to review the entire period until the RAI process is actually implemented and the burden is still on the entity to show compliance.** (2) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls, entity impact evaluation, and elimination of zero-defect expectations). The VSLs for Requirements R1 and R2 could be read to require self-reporting of every unit that tripped for a voltage or frequency excursion inside the no trip zone. To refocus NERC efforts on compliance, the recent reliability assurance initiative would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. These approaches are being written into the standards (CIP, COM-003, etc.). We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar

Organization	Yes or No	Question 5 Comment
		approach for this standard. **Requirements 1 and 2 are relay setting criteria requirements. Should there be an equipment limitation requiring that the relay settings of R1 and R2 be set in the "no trip zone" of Attachment 1 or 2, it is permissible to do so provided that the limitation is documented and communicated to the appropriate entity identified in R3. A violation of R1, R2, or R3 is either that the relays are not set according to the criteria of R1 or R2, or that documentation of the limitation (preventing the relays to be set according to R1 and R2) has not been communicated to the appropriate entity as required by R3.** (3) Because the voltage envelope is based on assumptions listed on page 19, the VSLs for R1 and R2 need to clarify that if a unit does trip in the no trip zone and the actual system conditions do not match these assumptions that the trip does not represent a violation. For instance, if a synchronous condenser or capacitor (bullet 2 under "Evaluating Protective Relay Settings" on page 19) is not available that was assumed to be available when evaluating protection relay settings, why would the GO be held accountable for its unit tripping during a voltage excursion? It followed the assumptions set out in the standard. **The clarifications have been revised to allow flexibility in the loading conditions when evaluating relaying settings. Please see the revised evaluation assumptions: "Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions."** (4) The response to our previous comments that requirement R3 and R5 are the types of requirements the Project 2013-02 Paragraph 81 drafting team is proposing to eliminate indicated that they do not meet criteria A. This implies that these requirements do provide significant reliability support. However, no justification for how they provide significant reliability support was provided. Please explain how a requirement such as R3 that requires documentation and communication supports reliability. Requirement R1 already allows a GO an exception for documented and

Organization	Yes or No	Question 5 Comment
		communicated equipment limitations. Because compliance is driven by evidence, the GO would have to document the limitation and communicate the limitation per the third bullet in Requirement R1. A separate requirement is simply not needed and "does little, if anything, to benefit or protect the reliable operation of the BES" above and beyond Requirement R1. The VSLs even seem to support this position since they focus primarily on the number of days late a registered entity has performed the task. Any further need to communicate the limitations could be rolled into the third bullet of Requirement R1. Requirement R5 is similarly situated requirement. Please explain how this requirement provides significant reliability support and, thus, does not meet criterion A. While we agree that generator protection settings changes need to be communicated, we simply do not see how a specific requirement to communicate them supports reliability. A requirement is not needed for every single task that should be completed. The requirement continues to perpetuate the paper driven compliance approach that NERC has recognized needs to change and is in the process of changing. If the drafting team believes, the requirement is still needed, we suggest including it as part of requirements R1 and R2. **Unless the GO indicates through communication to the TP (R3) that a particular unit will trip for voltage or frequency excursions not exceeding the "no trip zone" of the two attachments to the standard, the TP may not model the generator performance accurately, which may produce system simulations that are not valid. These erroneous studies could lead to actions (or inactions) that could affect system reliability.** **In the end, the requirement to document and communicate the limitations (and relay settings which are in the "no trip zone") have to be documented and communicated. It is more efficient to list these requirements once (in R3) rather than twice (in R1 and R2).**
Response: The GVSDT thanks you for your comment. Please see responses above.		

Organization	Yes or No	Question 5 Comment
Manitoba Hydro		(1) R4 - the word 'for' is missing between duration and which. **R4 has been removed from the standard.** (2) R4, second paragraph - the requirement hinges on what the GO 'expects' may happen, is very subjective. It will be hard for the MRO to measure compliance on this point. The phrase 'for the duration of the profile of the excursion' is new and not language that appears anywhere else in R4. It's not clear what it means. We would suggest using language that appears in the first paragraph of R4 so this is consistent. **R4 has been removed from the standard.** (3) R5 - allows the Planning Coordinator or Transmission Planner to request that settings must be provided within some time frame other than 60 days if they so direct. Theoretically this could be 1 day as there are no parameters put on what the PC or TP may direct. **The direction from the PC or TP was meant to be associated with the reporting of changes to the relay settings, not a change to the schedule. The requirement has been revised to clarify this: "Each Generator Owner shall provide its generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner (that models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes are not required."** (4) R5 - doesn't provide for a time frame other than 60 days which the requirement does. **The revision cited above addresses this concern.** (5) M2 - the word 'evidence' should be placed after 'have' and not after 'R2'. **The suggested revision has been made.**

Organization	Yes or No	Question 5 Comment
		(6) M3 - language doesn't seem to reflect revisions made to R3. For example, 'excluding limitations...' is still in M3 but deleted from R3. **Footnote 3 was revised to clarify the "excluding limitations…", and M3 has been revised to point to Footnote 3.** (7) M4 - language doesn't seem to reflect revisions made to R4. For example, the description of the generating units differs. **R4 / M4 have been removed from the standard.** (8) M5 - does not contemplate that it may be some time frame other than 60 days as R5 permits. **R5 has been revised to indicate that the "unless otherwise directed" phrase pertains to the reporting of changes rather than to the schedule.** (9) Compliance, 1.1 - CEA is used in the last sentence but never defined. The acronym is not used again, so it's likely easiest to not define it and use Compliance Enforcement Authority each time. **This has been corrected by adding (CEA) after Compliance Enforcement Authority in the first sentence.** (10) VSLs, R1 and R2 - the wording of the VSL is problematic as it ties the violation to a violation of R3 which the requirement itself does not do. **R1 and R2 specify exemptions to allow tripping in the "no trip zones" provided that the valid limitation is documented and communicated as specified in R3. Because this appears in R1 and R2, it is appropriate for it to appear in the VSL for R1 and R2.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Sacramento Municipal Utility District		1) Sacramento Municipal Utility District (SMUD) believes the applicability section should be revised to only cover those units defined by the BES Definition. As currently drafted Generator Owners that are registered under the NERC Registry

Organization	Yes or No	Question 5 Comment
		Criteria along with other non-registered generator owners are subject to this standard causing an enforcement issue. **While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word "unit(s)" in the requirements was modified to read "applicable unit(s)"** 2) SMUD thanks the SDT for their response to our comment on R6 (now R5) during the last posting. However, SMUD wishes reiterate our disagreement with a requirement mandates ALL generator protection settings. SMUD also find it problematic to allow a single request by the PC or TP to create an indefinite requirement to report any relay change. SMUD believes R5 should be limited in its application to only frequency or voltage settings that directly correspond with the measure the PC or TP implement in their studies. **The scope of the relays whose settings are to be supplied to the PC and TP has been revised to limit the scope of relays as you suggest. The revised requirement reads: "R4. Each Generator Owner shall provide its applicable generator protection trip settings *associated with Requirements R1 and R2* to the Planning Coordinator or Transmission Planner that models the associated unit…"**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Wisconsin Electric Power Company		1. The word "evidence" is missing in Measure M2. Also in Measure M2, the wording should be changed to add the phrase, "... or other documentation", to the list of acceptable evidence for Requirement R2. Measure M1 allows "other documentation" as evidence, and this should be true for Measure M2 also. **"Evidence" has been corrected in M2.** **"or other documentation" has been added to M2.**

Organization	Yes or No	Question 5 Comment
		2. We disagree that the applicability of this standard needs to be to all generators regardless of size or connection voltage. Only generators connected to the Bulk Electric System should be applicable. The efforts needed to meet these requirements will be significant, and should not be required for every generating unit. Please verify your understanding of the referenced FERC order, because resources are limited. **While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word "unit(s)" in the requirements was modified to read "applicable unit(s)"**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Tennessee Valley Authority		1. The technical justification for the need of a plant performance criteria appears to be based on issues with early design wind generation. The technical considerations at these types of generation stations are different than steam turbine generation plants, which require heavy induction loads to support operation and these loads are sensitive to upsets in voltage and frequency. The technical implications of the plant performance are not clear. Recommend generating a separate SAR and bring in industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical academia, etc. to assist in the technical analysis and standard development. **That is the direction that the SDT has chosen to follow as Requirement R4 has been removed from the current draft of the standard.** 2. Likewise, industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical academia, etc. can develop acceptable methods to determine the capability of a plant to ride through grid transients.

Organization	Yes or No	Question 5 Comment
		That is the direction that the SDT has chosen to follow as Requirement R4 has been removed from the current draft of the standard. 3. The following are IEEE Electric Machines Committee comments for PRC-024-1considerationThe IEEE Electric Machinery Committee hosted a discussion topic on “Grid Code Impact on Electric Machine Design” in San Diego at this year’s Power Engineering Society meeting and offers the following input. o Minor changes in the Under-frequency Ride Through Curve are suggested to better match existing machine design standards in IEEE C50????. o The PRC-024 Voltage Ride Through criteria is technically not ready to be a standard, for the following reasons;1. PRC-024 VR capability may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. It is believed the cost of complying with wider standards might increase main generator machine costs as much as25%, which is not insignificant. This should only be required if there is a defined local system need for higher standards and that these costs should be considered against the cost of other possible resolutions.2. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of all 4160V and 460V systems in new plant can be dynamically modeled to a degree allowing one to obtain non-dropout guarantees from equipment suppliers and EPC firms for extreme transients such as 2.0 seconds at 65% voltage, or that the same can be done for existing plants to allow identification of limiting components and accurate estimates of performance.3. The voltage ride through was originally intended to address early deficiencies in wind generation design only and it doesn’t make sense to apply such a broad curve to steam plants. The concerns

Organization	Yes or No	Question 5 Comment
		that led to the VRT curve for wind have been addressed by new vintage wind plant designs and thus, the EMC does not believe there is not driving need for a standard VRT criteria. o The VRT issue is holding up addressing other significant issues addressed by PRC-024 (relay setting coordination and frequency ride through). The VRT should be pulled out of PRC-024 and a new SAR drafted to address the voltage performance aspects if this is really needed for reliability. o More clarity in defining plant MVARs available to support grid voltage is needed. Specifically, generation plants have not been designed to operate outside a normal band of 95 to 105% on the generator terminals. GSU settings are typically chosen to optimize MVAR support under normal operations, however is not reasonable to assume the full leading or lagging reactive support would be available under normal grid conditions. **R4 has been removed from the current draft of the standard. The standard is now essentially a relay setting standard only. Generator performance requirements may or may not be dealt with in the future in other developments projects.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Duke Energy		a) The effective date in Section 5.1.4 should be increased to seven years. The typical major outage cycle for base load units can be as long as 7 to 9 years, based upon the unit and its history. **The SDT believes that five years is the correct number. The SDT notes that the maximum allowable interval for relay calibration in PRC-005-2 is six years. In addition, the SDT believes a major outage would not be necessary to effect a change in relay settings if that is what is necessary to comply with this standard.** b) In the “Consideration of Issues and Directives” document, it is stated that the

Organization	Yes or No	Question 5 Comment
		GVSDT believes that R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1, and that NRC requirements qualify as technical limitations for the purposes of this standard. We believe that additional clarity is needed in the text of Requirement R3 regarding allowable limitations other than equipment limitations, such as NRC technical specification limits and perhaps environmental permit limitations as well. **The SDT agrees and has added the words "…regulatory or…" before "… technical equipment limitation…" to address your concern.** c) Additional clarity is needed in Requirement R4. Is R4 intended to serve as a means to obtain more information from a Generator Owner about limitations identified pursuant to R3? Is the voltage or frequency profile to be provided by the Planning Coordinator or Transmission Planner different from Attachments 1&2? **Requirement R4 has been removed from this standard.** d) Requirement R4 states that the Generator owner may develop estimates based upon "sound engineering judgment". R4 should more clearly indicate the extent of "due diligence" effort that is expected in order to support an estimate based on "sound engineering judgment". **Requirement R4 has been removed from this standard.** e) On Attachment 2, Evaluating Protective Relay Settings, 1.c states that "Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals." We believe that compensating all generator voltage relaying for a loading of rated power at 0.95pf lagging is dangerous, as this could indicate coordination margin to the HVRT when there is none. The worst case coordinating conditions for the HVRT are not the same as for the LVRT. The current version of the standard is prescribing a method that will lead to miscoordination between the HVRT curve and overvoltage relays (59 & 24 elements). We recommend generator undervoltage relaying be evaluated at rated power at rated power factor, and generator overvoltage relaying be evaluated at rated power at .95pf leading. There

Organization	Yes or No	Question 5 Comment
		can be more than a 10% difference in POI voltage under these two sets of conditions. **The cited clarification specified the initial condition for the generator prior to an event that causes a voltage excursion. The words "… or loading conditions that are believed to be the most probable for the unit under study…" have been added to allow evaluation of the relay settings under conditions other than full load at 95% lagging power factor.** f) In the VRF and VSL Assignment document, the R6 should be corrected to R5 (typo) **The typo has been corrected.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Cowlitz PUD		(A) Confusion is created by making exemptions, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such "protective relays" meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% over speed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, "Excludes limitations that are caused by the generator frequency and voltage protective relays themselves." Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed.****** (B) The rationale for the last bullet item of R3.1 (reporting a 10% increase in

Organization	Yes or No	Question 5 Comment
		nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn't be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor mass flow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available.****** (C) Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation.****** (D) The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported

Organization	Yes or No	Question 5 Comment
		trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
Essential Power, LLC		a. Confusion is created by making exemptions, “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such “protective relays” meant to correspond to the “protective relaying” discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.” Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed . b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn’t be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow

Organization	Yes or No	Question 5 Comment
		uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. d. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
We Energies		a. Confusion is created by making exemptions, “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such “protective relays” meant to correspond to the “protective relaying” discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is

Organization	Yes or No	Question 5 Comment
		intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.” Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed. b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn’t be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant

Organization	Yes or No	Question 5 Comment
		blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. d. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
PPL Corporation NERC Registered Affiliates		Confusion is created by making grandfathering (exceptions), "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such "protective relays" meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any grandfathering is actually being allowed. It has been said in discussions with the SDT that there is no grandfathering of voltage-relaying or frequency-relaying intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations is in fact where our over/under-frequency protection system settings come from. If a turbine OEM notifies us that a unit must trip within one second at 2.5% overspeed, for example, then our 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, "Excludes

Organization	Yes or No	Question 5 Comment
		limitations that are caused by the generator frequency and voltage protective relays themselves." Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on historical practice with an unknown technical basis, a more direct way of saying so should be developed. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn't be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. It would be acceptable if R3.1 or a footnote stated that "Resubmittal of the exemption documentation when reporting a 10% increase in nameplate capacity is required, but the removal of the exemption status is not required as part of the 10% increase in nameplate capacity." Steam turbine off-frequency limits are generally set by OEMs as lifetime limits

Organization	Yes or No	Question 5 Comment
		regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.

Response: The GVSDT thanks you for your comment.

a. The GVSDT has decided to retain footnote 3 as it is a necessary clarification to Requirement R3. We have revised the footnote 3 to address your comment: "Excludes limitations that are caused by setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."

b. We have removed the last bullet from R3.

c. Requirement R3 provides the exemption for equipment limitations, which include off-frequency limits. Accrued off-frequency excursions are a valid equipment limitation and would be addressed in Requirement R3 but it is not required that this be done. We have added a bullet to R3 as: "• Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance."

d. The GVSDT intended for this requirement to include only those relays. We have added "associated with Requirements R1 and R2" to the requirement.

e. The GVSDT does not think that reporting relay setting changes within 60 days of a change is a burden. The TP and PC need to be made aware of the changes as soon as practical.

Organization	Yes or No	Question 5 Comment
Cogentrix Energy Power Management, LLC		a. Confusion is created by making exemptions, “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such “protective relays” meant to correspond to the “protective relaying” discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.” Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed . b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn’t be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability

Organization	Yes or No	Question 5 Comment
		pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation.
Response: The GVSDT thanks you for your comment. **a. The GVSDT has decided to retain footnote 3 as it is a necessary clarification to Requirement R3. We have revised the footnote 3 to address your comment: "Excludes limitations that are caused by setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."** **b. We have removed the last bullet from R3.** **c. Requirement R3 provides the exemption for equipment limitations, which include off-frequency limits. Accrued off-frequency excursions are a valid equipment limitation and would be addressed in Requirement R3 but it is not required that this be done. We have added a bullet to R3 as: "• Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance."**		
Associated Electric Cooperative, Inc. - JRO00088		AECI appreciates this SDT's demonstrated attention to industry feedback. Draft 5 PRC-024 R1 Bullet 3, COMMENT: AECI appreciates this "catch-all" being in there, and we hope it is worded to adequately cover any other technically justifiable

Organization	Yes or No	Question 5 Comment
		plant relay settings the SDT failed to mention, that intentionally operate within the industry's Attachment 1 No Trip zones. However we are concerned that R1's and Bullet #3's collective wording may specifically exclude any other protective relay settings outside of Bullet #1 and Bullet #2, including those specifically designed for other plant equipment limitations. (R2 Bullets #3 & #4 seem to provide better flexibility for what we failed to think of in this draft 5.) **Response: The SDT did add the additional qualifier in R1 Bullet 3 for "regulatory.....limitations" to remove any confusion that the allowance of tripping is not just limited to equipment limitations. Also, by NERC standard convention, a "bullet list" allows the entity to select which of the bulleted verbiage applies. Thus, the 3rd bullet would exclude the exceptions that are written in the first or second bullet.** Draft 5 PRC-024 page 14, Attachment 1, Curve Data Points:, Eastern Interconnection, COMMENT: It just seems that even without a fluctxuating frequency profile, the Eastern Interconnection's frequency-bounded curves, functionally-declared within that table's middle-row, can make a calculation for compliance with Requirements R1 & R4 a bit challenging. (Page 17's first bullet#3, providing clarity around evaluating step-wise voltage excursions, provided some insight into what is currently drafted for Requirements R1 and R4 in conjunction with Attachment 1, where these continuous Eastern Interconnection curves are in play, and actual plant performance studies and results are analyzed.) While we expect to evaluate plant performance only around our known discrete plant relay settings, we are a bit concerned for the way this Standard's non-discrete duration-functions might be leveraged against the industry when actual events occur. **Response: Since the Eastern Interconnection curve can be expressed by linear equations, which can be compared to the discrete plant relay settings, the SDT believes there isn't any risk of confusion of expected versus actual relay action during an event.** Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-Through Curve Clarifications,

Organization	Yes or No	Question 5 Comment
		Curve Details:, Bullet3:, REPLACE: "voltage exceeds", WITH: "voltage first exceeds", RATIONALE: Further clarity as to why duration is only 0.1 seconds in this example. **Response: The SDT has incorporated your suggestions** Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-through Curve Clarifications, Curve Details:, Bullet4:, REPLACE: "proportion to deviations of frequency below normal ", WITH: "proportion to below-normal deviations within the provided frequency profile", RATIONALE: Clarity that adjustment is made for study-related frequency profiles provided in conjunction with a request, and not for immediately experienced voltage deviations as they occur. **Response: In response to your and other industry comments, the SDT has modified the verbiage in Item 4 to reflect that a) this adjustment is associated with the determination of appropriate volts per hertz protection settings and b) by use of the qualifier "may", that this is a suggestion and not a requirement.** Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-Through Curve Clarifications, Evaluating Protective Relay Settings:, Bullet 1.c. REPLACE: "terminals).", WITH: "terminals.", RATIONALE: Balanced parentheticals **Response: The SDT has corrected the typo.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Tacoma Power		Applicability should only be to those units meeting NERC registration criteria. **Response: While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word "unit(s)" in the requirements was modified to read "applicable unit(s)"** Per Footnote 4, the "point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer." As the SDT is probably

Organization	Yes or No	Question 5 Comment
		aware, many generator protective relays measure voltage on the generation (low voltage) side of the transformer. It seems that guidance may be needed to reconcile generation (low voltage) side measurements with a standard whose requirements are based upon transmission (high voltage) side voltage. **Response: The SDT recognizes that the voltage ride through curve will have to be reflected through the transformer in order to determine the resulting voltage ride through curve that will be "seen" by the associated relays that are connected to instrument transformers on the generator side. Please reference Attachment 2 (Evaluating Protective Relay Settings section) for additional guidance regarding the assumptions that are expected to be made.** In R2, the phrase "less stringent" may not be clear enough language. For example, could "less stringent" mean 96-104%, rather than 95-105%, which is our assumption? Or, could it mean 94-106%? **Response: The SDT believes that the entire phrase clearly conveys the intent (less stringent voltage relay settings than those required to meet PRC-024 Attachment 2). It is meant to include the time period of the first 4 seconds.** Why are auxiliary systems mentioned in R4 but not in R1, R2, and R5? **Response: The SDT has removed R4. As such, auxiliary systems are no longer mentioned in any of the remaining requirements.** In R5, remove parentheses around "that models the associated unit." The parentheses seem to be inconsistent with similar text in R4. **Response: The SDT implemented your suggestion.** In M2, move 'evidence' to before "that generator voltage..." **Response: The SDT implemented your suggestion.** Attachment 2, Curve Detail 3, may need some better clarification. **Response: The SDT did slightly refine the language for clarity by inserting the word**

Organization	Yes or No	Question 5 Comment
		"first" into the second line (reference response to Associated Electric Cooperative, Inc for Question 5) Regarding Attachment 2, Curve Detail 4, does that mean a GO must base relay settings on the lowest expected frequency deviation? What is an example of how and when Detail 4 should be applied? **Response: The SDT modified the language to reference that an adjustment of the magnitude of the high voltage curve in proportion to deviations of frequency below normal should optionally occur when evaluating volts per hertz settings.** Regarding Attachment 2, Curve Detail 5, by stating "RMS or crest", does this mean that a GO must consider harmonics? Most simulations only consider the fundamental frequency component. In these cases, the per unit crest and RMS voltage should be identical. Clarification is requested. Examples are needed to support the application of Attachment 2, Evaluating Protective Relay Settings. **Response: In that the high-voltage curve establishes the minimum voltage at which a unit may be tripped by its protection, the original wording allowed consideration of the maximum of crest and RMS voltage. Having this provision makes the standard less limiting. There was no requirement for a GO to consider non-fundamental frequency voltages, there was permission to use peak-sensing or RMS-sensing protections (whether implemented via protective relays or via protections as part of controls). The information in Curve Detail 5 poses no burden on the GO, but rather allows a GO to provide better or more effective protection of certain types of equipment, if they choose to do so. To help provide clarity regarding the application of Attachment 2, the SDT revised the chart to provide ride-through durations at the associated voltage points.** R1, R2, and the diagram in Attachment 2 appear to be fairly straightforward. However, the Voltage Ride-Through Curve Clarifications page (last page) seems to confuse, not clarify. This last page seems to undermine the apparent simplicity of the rest of the standard with respect to voltage protective relay settings.

Organization	Yes or No	Question 5 Comment
		Response: The SDT has made a number of refinements to the Voltage Ride-Through Curve clarification page such as a) modified the language to convey in the Curve Detail section Item 4 that an adjustment of the magnitude of the high voltage curve in proportion to deviations of frequency below normal should optionally occur when evaluating volts per hertz settings, and b) modifying the Evaluating Protective Relay Settings section to allowing the responsible entity the ability to assume the most probable loading conditioning, and clarifying that the AVR should be assumed to be in service. In Attachment 2, the Curve Data Points table needs to be updated to reflect the Voltage Ride-Through Time Duration Curve. Tacoma Power appreciates the opportunity to provide comments, and thanks you for consideration of our comments. **Response: The SDT has corrected the Table to reflect that it is applicable up to 4 seconds.**
Response: The GVSDT thanks you for your comment.		
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the suggested revision to the VSLs.		
Bonneville Power Administration		BPA believes that the standard should combine bullet 3 into bullet 2 in R3.1 (and modify bullet 3 to notify when equipment has been replaced for whatever reason) o Identification of an equipment limitation. o Repair or replacement of the

Organization	Yes or No	Question 5 Comment
		equipment causing the limitation that removes the limitation. o Replacement of the equipment causing the limitation. (modification)
Response: The GVSDT thanks you for your comment. The SDT developed the bullet items during the last posting based on stakeholder comments. The GVST believes that we have achieved stakeholder consensus on this language.		
CenterPoint Energy		CenterPoint Energy does not agree that a Planning Coordinator or a Transmission Planner should be required to provide a voltage or frequency profile at the point of interconnection that is determined by dynamic simulation and, instead, recommends that the voltage or frequency profiles in Attachment 1 and Attachment 2 be referenced. Different types of simulated events will produce different voltage and frequency excursions. Also, even the same type of event will produce different voltage and frequency excursion "profiles" as the system changes over time. Therefore, the voltage or frequency profiles in Attachment 1 and Attachment 2 should be used.
Response: The GVSDT thanks you for your comment. The wording in Requirement R2 gives the Planning Coordinator or Transmission Planner the option to provide a site-specific voltage profile, but does not require that it be done. Requirement R4 contained wording that required the PC or TP to provide a profile to the Generator Owner before asking for an estimate of ride-through time, but Requirement R4 has been removed from the standard.		
Cleco		Cleco is concerned the approach is too prescriptive given the numerous variables associated with generator performance and protection. We recommend the elimination of requirements R1 and R2 in their entirety. **The SDT disagrees with this suggestion. These two requirements form the backbone of this standard. The UFLS standard (PRC-006-1), in particular, refers to PRC-024-1 for information and proper setting of generator frequency protection.** We further recommend requirement R3 be modified so that the generator owner is required to develop a unit capability curve for frequency and voltage based on equipment limitations and protection requirements and provide this information to

Organization	Yes or No	Question 5 Comment
		the appropriate users. This approach emphasizes equipment preservation and safety while retaining predictability of unit performance for system modeling. We would also like an example for how to evaluate Volts/Hertz protection for the proposed voltage curve. **The SDT disagrees that drafting multiple sets of unit capability curves for different frequencies and voltages would be of value. The capability curves are meant for steady state operation, not the transient conditions considered in this standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Kansas City Power & Light		Comment 1;Generator protective relays are connected to the potential transformers on the generator side of the GSU transformer. The interconnection point is defined by the standard on the transmission side of the GSU. The voltage and frequency charts in the attachments are requirements at the interconnection point. Therefore the standard prevents the use of existing generator protective relays for voltage or frequency protection. The standard and attachment charts should be redrafted to represent the interconnect point on the generator side of the GSU so existing multifunction relays can be used for voltage and frequency protection. **The SDT disagrees that the standard prevents the use of existing generator protective relays, but it would require the evaluation of the voltages at the generator terminals that result from the described transmission system voltage excursions based on the specific transformer tap, transformer impedance, and generator reactance. Because of these variables, the SDT does not believe the voltage excursion curves can be described for all generators at the generator terminal level.** Comment 2; Requirement 5 states “Generator Owner shall provide its generator protection trip settings to the Planning Coordinator, etc”. In the context of this standard I would assume that generator protection trip settings would be those settings relative to voltage or frequency protection and for example would not

Organization	Yes or No	Question 5 Comment
		include back up distance settings. The standard should be modified to clarify which generator protective relay settings are required for compliance. **The SDT agrees. The words "… associated with Requirements R1 and R2…" have been added to clarify the scope of the requirement.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Consumers Energy Company		Consumers Energy is resubmitting our original comments as we feel they still pertain. "Related to undervoltage criteria, the 18 cycle at 45% of generator voltage would put a great deal of strain on the plant auxiliary systems and that may not be something these systems are able to withstand. The same would be true of a fault that produces 65% voltage at the generator terminals for 2 seconds. These comments relate specifically to Consumers Energy. However, it is likely that many others have similar equipment and would have the same issues. Please also note that the proposed standard does not align with ANSI C37.102, IEEE Guide for AC Generator Protection or with the NERC Technical Reference Document entitled Power Plant and Transmission System Protection Coordination." Previous SDT reply - Thank you for your comments. Please note that the voltage levels specified in Attachment 2 are at the point of interconnection to the transmission system. They would not correlate directly with the auxiliary bus voltages, especially if the auxiliaries are unit-connected. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. Please inform the SDT of the specifics of your concerns." We believe our comments still apply. Specific to the fault that produces 65% voltage at the generator terminals for 2 seconds, plant auxiliary equipment would not be able to withstand such a drop for the specified duration and would fall offline.SDT Reply - The SDT thanks you for your comments. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. The SDT believes that the wording of R4, "The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment," will allow the GO to provide an estimate. However, if the GO feels his equipment is not

Organization	Yes or No	Question 5 Comment
		capable of meeting the undervoltage criteria of Attachment 2, then R3 would apply. Also, note that Attachment 2 has been modified for the next draft and now only extends to 4 seconds.
Response: The GVSDT thanks you for your comment. The GVSDT points out that the voltage shown in attachment 2 is at the Point of Interconnection and not at the generator terminals. This is shown in the axis label on the right side of the curve.		
Exelon Corporation and its affiliates		Exelons negative vote is based on the following: Exelon reiterates that nuclear generating units must comply with a rigorous process of evaluation to meet requirements of the Nuclear Regulatory Commission (NRC). The response by the SDT in the Consideration of Comments dated 12/7/12 that "the SDT does not believe extensive studies or dynamic simulations are required to comply with this requirement" does not address the fact that NRC licensed nuclear generating units must also comply with the requirements of the NRC. Exelon again does not agree that 60 calendar days is a reasonable amount of time to perform any such analysis.
Response: The GVSDT thanks you for your comment. The words "regulatory and" have been added in several locations throughout the standard to emphasize the exemptions from the requirements specified in R1 and R2 are allowed for both regulatory limitations and technical equipment limitations. Please review these modifications to R1, R2, and R3. Also, the GVSDT has removed the requirement to provide an estimate of the time duration a unit is expected to remain connected during a voltage or frequency excursion.		
Idaho Power Company		Idaho Power's Power Supply group feels that Requirements 1 through 4 accomplish the purpose of PRC-024 and that Requirement 5 is not necessary and in fact creates an on-going obligation for the generation owner to continually provide relay settings to the Transmission Planner within 60 days of any change to those settings regardless of the relay setting changes impact on reliability and even if the changed settings remain in compliance with R1 and R2 of the standard. However, Idaho Power's System Planning group feels that Requirement 4 is not a sufficient mechanism to collect the desired data and removal of R5 will limit the Planning Authority's ability to request relay modeling data from both Idaho Power and non-Idaho Power Generator

Organization	Yes or No	Question 5 Comment
		Owners. **R4 has been deleted from the draft standard. The relay setting communication requirement (R5, draft 5) is now R4 (draft 6). The scope of relays whose settings may be requested has been clarified in the new R4. The GVSDT does not think that reporting relay setting changes within 60 days of a change is a burden. The TP and PC need to be made aware of the changes as soon as practical.** R5 will make it a compliance obligation for GOs, to provide the required data when requested by a PA/PC or TP in a timely manner, or following a change in relay settings on a generator for which said data had previously been requested. Idaho Power notes the Measure 2 should read: Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies."Idaho Power comments that reference to the Planning Coordinator entity throughout the PRC-024 standard should be replaced with the term Planning Authority to be consistent with the NERC Glossary of Terms. **Please see version 5 of the NERC Functional Model and the current NERC Glossary of terms, both of which identify the PC as the correct term. The term Authority is being transitioned to Coordinator.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
IRC Standards Review Committee		In order for the industry to support the proposed change to the high frequency trip curve in Attachment 1, we propose that the SDT provide the technical justification and an assessment of the system impacts as a result of the proposed change so operators are aware of and manage the resultant system response. We believe the standards should be based upon actual technical data rather than conditions represented in the IEEE and IEC standards.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set		

Organization	Yes or No	Question 5 Comment
overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards.		
MRO NSRF		In R3, the NSRF recommends that 30 day requirement be replaced with "in a timely manner not to exceed 90 days". This is predicated on the low VRF and low risk of impacting the BES. While some deadlines are necessary in NERC standards, large frequency and voltage excursions are rare and there would be little to no reliability difference if R3 changes were communicated in a time frame longer than 30 days. **The SDT believes that once it has been determined that an additional notification from the GO to the PC and TP is necessary, the 30 days allowed for notification is not burdensome.** In R3, the fourth bullet, delete (cumulative from the first effective date of this standard). This creates an unnecessary compliance tracking burden. Entities must forever memorialize all equipment capability from the effective date of the proposed standard such as 2014. There is no reason to track all possible equipment changes in 2044 back to 2014 to show that a 10% upgrade has not occurred is pieces throughout the years. Transmission and generation upgrades are usually lumped and somewhat large as it is usually cost prohibitive to increase generator capability. The reliability benefit is to recognize when a large change in the limitation occurred, not to track a cumulative 10%. Is the SDT referring to only the limiting element that needs to be tracked? **This bullet has been deleted from the draft standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Avista		Most frequency relays have voltage supervision. There is no voltage supervision requirement for frequency relays specified in the standard. For the voltage relay settings the ride through is given as 9 cycles at 0 volts. Where did the 9 cycles come from?

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. The frequency and voltage protection are considered to be different functions so the voltage ride through and frequency ride through are not expected to happen at the same time. It is not the intent of the SDT or this standard to specify the relay design, merely the coordination of the protection settings with the standard or equipment or equipment limitations, whichever is more restrictive. The nine cycle time came from the WECC studies performed relating to the voltage ride through characteristics and FERC Order 661A (Appendix G).		
ReliabilityFirst		ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comment for consideration: 1. Requirement R3 Part 3.1 a. To be consistent with the changes made to Requirement R4 and new R5 (removal of Reliability Coordinator and Transmission Operator), ReliabilityFirst recommends removing references to the Reliability Coordinator and Transmission Operator from Requirement R3 Part 3.1 as well. Requirement R3 is long-term planning requirement and communication of the documented equipment limitations to these entities should not be required.
Response: The GVSDT thanks you for your comment. The SDT agrees and has removed the Reliability Coordinator and Transmission Operator from Requirement R3 and the associated VSLs as well as the Purpose Statement.		
seattle city light		Seattle CIty Light, from a GO perspective, will vote NO, because it is unclear the type of data the TP is to provide the GO. Until the TPs agree to and approve acceptable simulations and dynamic models, it is difficult for us to approve this standard.
Response: The GVSDT thanks you for your comment. The SDT has decided to remove Requirement R4 from the standard so any reference in Requirement R4 to the frequency and voltage profiles which were to be provided by the Planning Coordinator or Transmission Planner is no longer valid. Requirement R2 allows the Transmission Planner to provide a less stringent voltage profile than that in Attachment 2 if they feel it is more appropriate.		
Xcel Energy		Suggest improving consistency between R1 and R2 verbiage by addressing the

Organization	Yes or No	Question 5 Comment
		following editorial comments: (a) Not sure why the qualifying phrase "... as a result of voltage excursion (at the point of interconnection)..." is used in R2 but no corresponding qualification is used in R1? If this specificity for voltage excursion is needed in R2, then shouldn't it also be needed for frequency excursions in R1? **A voltage excursion would be location specific and is referenced to the point of interconnection as opposed to the generator terminals where the measurement would be significantly different A frequency excursion is different and may be measured the very nearly the same no matter where it is viewed in the interconnection. For the GO, there would be no difference measuring the frequency either at the generator terminals or at the point of interconnection. For these reasons the qualifying phrase was necessary for Requirement R2.** (b) Re-order the bulleted exceptions under R1 and R2 such that they appear in the same sequence in both requirements - this will make it easier for the uninitiated reader to observe that R1 and R2 share 3 common exceptions and R2 has one additional exception. **The SDT feels that changing the order will add little to the readability, even for the uninitiated and therefore prefer not to change the order and confuse those already initiated.** (c) Readability and comprehension of R2 will be significantly enhanced if it is simplified by splitting it into 2 or more shorter sentences. Its existing structure - a very long, compound sentence of more than 100 words - is not conducive to easy comprehension and is prone to ambiguities in interpretation, leading to compliance confusion. **The SDT agrees and has revised Requirement R2 into multiple sentences for enhanced readability. Requirement R2 now reads in part:** **"Each Generator Owner that has generator voltage protective relaying activated to trip its generating unit(s) shall set its protective relaying such that the voltage**

Organization	Yes or No	Question 5 Comment
		protective relaying does not trip as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the generator owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: ……" (d) R1 states "Each GO.... shall set <such> protective relaying <so> that the.... does not <operate to> trip" whereas R2 states "Each GO..... shall set <its> protective relaying <such> that the.... does not trip". It is hard to detect any good reason for the choice of words <such> and <so> in R1 versus <its> and <such> in R2, or for choosing to say <operate to> trip in R1 versus omitting that phrase in R2. Suggest identical lead-in sentences unless there is a good reason for the variations. **The SDT agrees and has modified the wording in Requirement R1 to match that in Requirement R2 as suggested.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Oncor Electric Delivery Company LLC		The 60 calendar day requirement in Requirement 5 for a Generator Owner to respond to a written request from its Transmission Planner or Planning Coordinator for generator protection trip settings, is too long. Because of the critical nature of this information, prolonging assessing system coordination can result in an unnecessary risk to the reliability of the Bulk Electric System. Oncor requests that this time requirement be shortened to 30 days.
Response: The GVSDT thanks you for your comment. The SDT considers this standard to be on a unit basis and that 60 days should be adequate for any single unit.		

Organization	Yes or No	Question 5 Comment
Wolverine Power Supply Cooperative, Inc.		The applicability should be restricted to BES generating units, not all units.
Response: The GVSDT thanks you for your comment. While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word "unit(s)" in the requirements was modified to read "applicable unit(s)"		
Ameren		The SDT has addressed all of our comments by changing several items that improve the standard, and especially important to us was removing R5 & M5. However, the SDT did not alter the VSL from the 10 day escalation for R3 through R5, and used the NERC guidance as their reason. NERC guidance also allows for a population based severity escalation, which we believe is more appropriate for characterizing the severity in situations such as this, and so we recommend using this approach. We suggest allowing up to 5% for Low, 5 to 10% for Moderate, 10 to 15% for High, and greater than 15% for Severe. For example, change the R4 Lower VSL to "The Generator Owner provided an estimate for less than 100% but more than 95% of its units' performance within 60 calendar days of a written request" and change R4 Moderate VSL to "The Generator Owner provided an estimate for 95% or less, but more than 90% of its units' performance within 60 calendar days of a written request."
Response: The GVSDT thanks you for your comment. As a result of other stakeholder comments the SDT has removed Requirement R4. The SDT views this standard on a unit basis and not a fleet basis so the percentage basis would be inappropriate. The SDT however did modify the VSL's for Requirements R3 and R5 (now R4) to match the 30 day escalation in some of the other generator verification standards of Project 2007-09.		
Appelbaum		The VRF for R1 and R2 should be High not Medium. The Drafting team in the VRF justification document states [Start quote] This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple

Organization	Yes or No	Question 5 Comment
		elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated.[End Quote] I disagree with the assertion. PRC-023 is violated if one relay is incorrectly set regardless of the number of elements it is protecting. The same applies to PRC-024, a failure to set one relay will effect one generator. Also for PRC-023 a single violation would not lead to BES cascade but that reasoning did not prevent a VRF of High to be established for PRC-023. Applying consistent reasoning to PRC-024 would mean that the single generator argument to reduce the VRF to medium would not apply.
Response: The GVSDT thanks you for your comment. The justification for the VRF must include all of the reasoning and guidelines referenced in the justification document. The VRF's were previously changed from high to low based on the following comment from a previous posting, "We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary." This comment was accepted by the SDT and since yours was the first and only objection; the SDT believes industry consensus has been achieved.		
American Electric Power		We agree with the overall approach taken, however we are concerned that the standard repeatedly references "protective relaying" while Footnote 1 clarifies that protective relaying could be discrete relays as well as protective functions within control systems. The term "protective relay" is widely accepted amongst engineers as meaning a discrete relay. AEP recommends the SDT utilize the term "protective functions" throughout the standard to clearly identify that the scope of the standard extends beyond discrete relays.AEP recommends that the time allowed to meet R 3.1 be extended to 60 calendar days, aligning it with R4 and R5.

Organization	Yes or No	Question 5 Comment
		The SDT has included the clarification in Footnote 1 to point out that the use of protective relaying as intended in this standard includes those functions that might not normally be recognized as "protective relaying". The SDT purposely did not use the term "protective functions" throughout so as not create confusion over other protective functions found in control systems such as overspeed trips that might be found in turbine controls. AEP recommends R4 and R5 be revised to read "within 60 calendar days or an agreed upon schedule". The data sought by the PC or Transmission Planner might be quite large for some utilities. In this case, it would be advantageous to allow the GO to work with the requesting party to develop a timeline that meets the needs of the requesting party without being overly burdensome to the GO. We believe the intent of the SDT in requiring the GO to provide updates on any previously requested trip settings in R5 was to ensure that the PC and TP are notified of any changes to the R1 and R2 applicable trips. If this is accurate, we suggest revising R5 to require the GO to update the PC and TP within 60 days of installation of new trips or changes to existing trips to which R1 and R2 applies, not solely those trip settings previously requested by the PC and TP. Doing so removes the obligation of the GO to track which trip settings were part of a previous request. This change will also eliminate the possibility of the TP or PC not being made aware of a newly installed applicable trip within a timely fashion. **The SDT has decided to eliminate R4 from the standard, which is perceived to be your primary concern, due to other stakeholder comments. The Requirement in R5 to submit settings that should already be on file within 60 days is not considered by the SDT to be burdensome.** Should the 10 percent generator nameplate capacity increase stipulation in the last (fourth) bullet point under R3.1 be removed? We do not see that the stipulation is relevant to the question of what limitation is causing a given generating unit to not satisfy R1 or R2 criteria. Perhaps the point should read as follows: "Modification or upgrade of the equipment causing the limitation that removes or changes the

Organization	Yes or No	Question 5 Comment
		limitation.” **The SDT agrees and has removed the referenced bullet from Requirement R 3.1.** With reference to R4, would it make sense for the TP or PC to specify Attachments 1 and 2 as the profiles for the purpose of collecting time duration estimates, or should the term “profile” instead be “trajectory”? From the viewpoint of the TP or PC, receiving duration estimates with respect to the Attachments would be advantageous, particularly when coordinating generator off-nominal frequency tripping with UFLS. However, a single duration estimate seems more compatible with a frequency or voltage trajectory. Which is the SDT’s intent? **As a result of stakeholder comments the SDT has decided to eliminate Requirement R4 from the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Ingleside Cogeneration LP		While we were pleased to see the removal of R5 from PRC-024, there is still some question as to the basic necessity for this standard, PRC-001, now PRC-027, requires extensive coordination of protection system relay setting between GOs and TOs. Interconnection agreements also require following voltage schedules, etc. This is a case of over regulation and potential conflicts between standards, something Paragraph 81 initiative is supposed to oppose. Also, there is no explicit FERC directive that requires this standard.
Response: The GVSDT thanks you for your comment. As stated in the purpose, this standard is intended to “Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.” and is not for the coordination of protection settings among entities (PRC-001.1). There is no approved PRC-027but even its draft is primarily related to coordination of interconnected elements. Industry determined in the SAR, as a result of the Phase III and IV testing that the standard was needed. Standards are not usually directed by FERC but determined by SAR’s.		
Liberty Electric Power LLC		Yes. First, the standard as presented is greatly improved from the prior version. The hard work of the SDT is apparent. However, there still are a few issues which should

Organization	Yes or No	Question 5 Comment
		be resolved with the standard. First, the 10% trigger for removing exemptions is too low. GE markets products for their gas turbines which can raise output more than 10% through software changes. This could place a turbine into no exemptions space while it still contained blades subject to failure at frequencies within the no trip zone. The 10% threshold should be raised or the standard reworded to note that software changes do not trigger the requirement. **The SDT agrees and, with the elimination of R5 from the previous revision, has decided that the 10% trigger found in Requirement R 3.1 no longer applies. Therefore the bullet containing the 10% trigger has been eliminated from the standard.** Secondly, the phrase "manufacturers advisory" is too vague. One reasonable person may read the phrase as "a statement in the OEM materials which places limits on the frequencies the machine can tolerate", while another reasonable person would define it as "a specific bulletin or technical information letter which advises of a finding about the equipment". GE 7FA OEM documents, for example, state that the turbine is "very sensitive to abnormal frequencies" and that recommendations "should be carefully studied and followed". Would this document, coupled with an engineer determining an overfrequency relay setting of 60.5 with 60 cycle delay, be enough to allow that setting? Would something like this be subject to individual auditor determination? If the latter is true, the wording should be changed, as requirements should clearly guide the entity in making a determination of the allowable action. **We have revised the word "advisory" to "advice" to help clarify the issue and address your concern.** Finally, if a steam turbine which is driven by steam generated from gas turbine exhaust is required to trip within the no-trip zone due to equipment limitations, does this allow those gas turbines to trip within the no trip zone also, in order to prevent damage to the steam turbine condenser? Can their protective settings for overfrequency be set at the same point as the required steam turbine settings, or

Organization	Yes or No	Question 5 Comment
		would an entity have to add logic to their system to trip in response to the activation of the steam turbine overfrequency trip instead of their own overfrequency relay? **The standard in no way suggests that the unit should be operated in a manner which is detrimental to the equipment. An exemption would include any part of the unit (gas turbines in a combined cycle unit for this case) that should be tripped to protect the equipment if it is a documented limitation.**
Response: The GVSDT thanks you for your comment. Please see responses above.		

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on August 18, 2007.
5. Draft 1 MOD-026-1 was posted for a 45-day comment period from February 17 – April 2, 2009.
6. Draft 2 MOD-026-1 was posted for a 45-day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of MOD-026-1 was posted for a 30-day concurrent comment and successive ballot period from February 29 – March 29, 2012.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This fourth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop fourth version of draft standard.	April– July 2012
2. Post response to comments and fourth version draft revision of standard for 30-day comment and successive ballot period.	October – November 2012
3. Develop responses to successive ballot comments.	December 2012 - January 2013
4. Post response to comments and conduct recirculation ballot.	February 2013
5. BOT adoption.	March 2012
6. File with regulatory authorities.	April 2013

A. Introduction

1. Title: Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

2. Number: MOD-026-1

3. Purpose: To verify that the generator excitation control system or plant volt/var control function[1] model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. Applicability:

4.1. Functional Entities:

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities:

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an "applicable unit" that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

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[1] Excitation control system or plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation and power system stabilizer.

b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 For all Interconnections:

- A technically justified[2] unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner.

5. Effective Date:

5.1. For Requirements R1, and R3 through R6, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years

[2] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request : *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of excitation control system or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic excitation control system or plant volt/var control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific excitation control system or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification for individual units less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s), or both. Each verification shall include the following:

2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,

2.1.2. Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed),

2.1.3. Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator,

2.1.4. Model structure and data for the excitation control system, including the closed loop voltage regulator if a closed loop voltage regulator is installed or the model structure and data for the plant volt/var control function system,

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used, and

2.1.6. Model structure and data for power system stabilizer, if so equipped.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit:

- Written notification from its Transmission Planner (in accordance with Requirement R6) that the excitation control system or plant volt/var control function model is not usable,
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system or plant volt/var control function model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated excitation control system or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[3] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[4] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the excitation control system or plant volt/var control function that alter the equipment response characteristic.[5] *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

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[3] If verification is performed, the 10-year period as outlined in MOD-026 Attachment 1 is reset.

[4] Ibid

[5] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

R5. Each Generator Owner shall provide a written response to its Transmission Planner, within 90 calendar days following receipt of a technically justified[6] unit request from the Transmission Planner to perform a model review of a unit or plant that includes one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Details of plans to verify the model (in accordance with Requirement R2), or
- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.

R6. Each Transmission Planner shall provide a written response to the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 6.1 through 6.3) or is not usable.

6.1. The excitation control system or plant volt/var control function model initializes to compute modeling data without error,

6.2. A no-disturbance simulation results in negligible transients, and

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator excitation control system or plant volt/var control function model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence

[6] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 180 calendar days of making changes.

M5. Evidence for Requirement R5 must include the Generator Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 90 calendar days following receipt of a technically justified request.

M6. Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for three calendar years from the date the document was provided.

- The Generator Owner shall retain the latest excitation control system or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner after the timeframe specified in MOD-026 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner verified models that omitted one of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted two of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) but omitted four or more of the six parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice. OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.
R5	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner failed to provide a written response to the Transmission Planner within 180 calendar days following receipt of a technically justified request to perform a model review of an applicable unit. OR The Generator Owner’s written response failed to include one of the sub bullets of Requirement R5

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for all specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, “Model Validation for Wind Turbine Generator Models”, IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, “Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, “Dynamic Modeling of GE Wind Plants for Stability Simulations,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, “Description and Technical Specifications for Generic WTG Models – A Status Report,” Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ

9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, “Modeling of GE Wind Turbine-Generators for Grid Studies,” version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, “Field Testing & Model Validation of Wind Plants,” in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, “Experience with Field and Factory Testing for Model Validation of GE Wind Plants,” in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belgium, March/April 2008
13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
14. W.W. Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, “Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations,” Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003
17. P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 10-year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-026 Attachment 1

Excitation Control System or Plant Volt/Var Function Model Verification Periodicity

Row Number	Verification Condition	Required Action
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
5	The Generator Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
6	New or existing applicable unit does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 3 for a “New Generating Unit” (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).
7	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10-year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Establishing the recurring 10-year unit verification period start date:

The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 2: Consideration for early compliance:

Existing generator excitation control system or plant volt/var control function model verification is sufficient for demonstrating compliance for a 10-year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on August 18, 2007.
5. Draft 1 MOD-026-1 was posted for a 45-day comment period from February 17 – April 2, 2009.
6. Draft 2 MOD-026-1 was posted for a 45-day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of MOD-026-1 was posted for a 30-day concurrent comment and successive ballot period from February 29 – March 29, 2012.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This fourth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop fourth version of draft standard.	April– July 2012
2. Post response to comments and fourth version draft revision of standard for 30-day comment and successive ballot period.	October – November 2012
3. Develop responses to successive ballot comments.	December 2012 - January 2013
4. Post response to comments and conduct recirculation ballot.	February 2013
5. BOT adoption.	March 2012
6~~7~~. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

2. **Number:** MOD-026-1

3. **Purpose:** To verify that the generator excitation control system or plant volt/var control function[1] model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities:

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an “applicable unit” that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

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[1] Excitation control system or plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation and power system stabilizer.

b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 For all Interconnections:

- A technically justified[2] unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner.

5. Effective Date:

5.1. For Requirements R1, and R3 through R6, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ~~thirty~~ that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years

[2] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide ~~one or more of~~ the following requested information to the~~to its requesting~~ Generator Owner within 90 calendar days of receiving a written request : *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of excitation control system or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic excitation control system or plant volt/var control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific excitation control system or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification ~~of an~~for individual units less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or ~~plant~~ aggregate unit model(s), or both. Each verification shall include the following:

2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,

2.1.2. Manufacturer, model number (if available), and type of the excitation control system ~~or plant volt/var control function installed~~ including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed),

2.1.3. Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator,

2.1.4. Model structure and data for the excitation control system, including the closed loop voltage regulator if a closed loop voltage regulator is installed or the model structure and data for the plant volt/var control function system,

2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used, and

2.1.6. Model structure and data for power system stabilizer, if so equipped.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit:

- Written notification from its Transmission Planner (in accordance with Requirement R6) that the excitation control system or plant volt/var control function model is not usable,
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system or plant volt/var control function model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated excitation control system or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[3] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[4] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the excitation control system or plant volt/var control function that alter the equipment response characteristic.[5] *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

[3] If verification is performed, the 10-year period as outlined in MOD-026 Attachment 1 is reset.

[4] Ibid

[5] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

R5. Each Generator Owner shall provide a written response to its Transmission Planner, within 90 calendar days following receipt of a technically justified[6] unit request from the Transmission Planner to perform a model review of a unit or plant that includes one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Details of plans to verify the model (in accordance with Requirement R2), or
- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.

R6. Each Transmission Planner shall provide a written response to~~notify~~ the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 6.1 through 6.3) or is not usable. ~~If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

6.1. The excitation control system or plant volt/var control function model initializes to compute modeling data without error,

6.2. A no-disturbance simulation results in negligible transients, and

6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator excitation control system or plant volt/var control function model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

[6] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 180 calendar days of making changes.

M5. Evidence for Requirement R5 must include the Generator Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 90 calendar days following receipt of a technically justified request.

M6. Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for three calendar years from the date the document was provided.
- The Generator Owner shall retain the latest excitation control system or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner after the timeframe specified in MOD-026 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner verified models that omitted one of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted two of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1. OR The Generator Owner provided the Transmission Planner verified models that omitted three of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.	The Generator Owner provided its verified model(s), including documentation and data more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1. OR The Generator Owner provided the Transmission Planner verified model(s) but omitted four or more of the six parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice. OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.
R5	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner failed to provide a written response to the Transmission Planner within 180 calendar days following receipt of a technically justified request to perform a model review of an applicable unit. OR The Generator Owner's written response failed to include one of the sub bullets of Requirement R5

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information. OR The Transmission Planner's written response omitted confirmation for all specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, “Model Validation for Wind Turbine Generator Models”, IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, “Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, “Dynamic Modeling of GE Wind Plants for Stability Simulations,” IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, “Description and Technical Specifications for Generic WTG Models – A Status Report,” Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ

9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, “Modeling of GE Wind Turbine-Generators for Grid Studies,” version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, “Field Testing & Model Validation of Wind Plants,” in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, “Experience with Field and Factory Testing for Model Validation of GE Wind Plants,” in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belgium, March/April 2008
13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
14. W.W. Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, “Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations,” Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003
17. P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 10-year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
5	The Generator Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
6	New or existing applicable unit does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 3 for a “New Generating Unit” (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).
7	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10-year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Establishing the recurring 10-year unit verification period start date:

The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 2: Consideration for early compliance:

Existing generator excitation control system or plant volt/var control function model verification is sufficient for demonstrating compliance for a 10-year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

NERC
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RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units."

Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant / Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

For all Interconnections:

- Any technically justified[1] unit that meets NERC registry criteria and is requested by the Transmission Planner.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA are compliant with Requirement R2 By the first day of the first calendar quarter, 10 years

[1] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA is compliant with Requirement R2 By the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a 10 year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the 10 year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements 10 years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Retirements

None

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Approvals Required

MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units."

Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant consisting of multiple units that are directly connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant / Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

For all Interconnections:

- Any technically justified[1] unit that meets NERC registry criteria and is requested by the Transmission Planner.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 By the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA are compliant with Requirement R2 By the first day of the first calendar quarter, 10 years

[1] Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R6 by the first day of the first calendar quarter following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection is compliant with Requirement R2 By the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure 100 percent of its applicable unit gross MVA is compliant with Requirement R2 By the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Consideration for Early Compliance

Existing excitation control system and plant volt/var control model verification is sufficient for demonstrating compliance for a 10 year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification, or
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Justification

This phased implementation supports the 10 year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules.

When a Generator Owner has verified its Excitation Control System and Plant Volt/Var Control model(s) in compliance with its regional entity requirements 10 years or less prior to the approval date of this Standard, these verifications are deemed sufficient for demonstrating compliance with this Standard for a ten year period from the date of the aforementioned verification.

Retirements

None

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed (August 18, 2007).
5. First Draft of MOD-024-2 was posted for comment January 18 – February 18, 2010. MOD-024-2 was later combined with MOD-025-1 to form MOD-025-2.
6. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
7. Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.
8. Posted third draft of standard for 30-day concurrent formal comment period and initial ballot September 28 – October 31, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 30-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post responses to comments and conduct recirculation ballot.	December 2012
2. BOT adoption.	February 2013
3. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

   4.1. Functional entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities:

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required[1]:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required[2]:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Note: The verification percentage above is based on the number of applicable units owned.

[2] Wind farm verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Requirements

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units.

3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

B. Measures

M1. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R1.

M2. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, or dated information collected and used to complete attachments and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R2.

M3. Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing 1 to less than or equal to 33 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing more than 33 to 66 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data. OR	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner failed to verify the Real Power capability, per Attachment 1 of an applicable generating unit. OR The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item

	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R2	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the Reactive	The Generator Owner verified and recorded the Reactive Power

	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Generator Owner performed the Reactive Power verification per	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2	Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72	capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR

	Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	(5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	calendar months but less than or equal to 75 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R3	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120	The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150	The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is

	than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less	calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.	calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.	recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit. OR The Transmission Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15calendar months.

	than or equal to 69 months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	OR The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	

D. Regional Variances

None

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
Version 1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06
Version 2	TBD	Revised per SAR for Project 2007-09 and combined with MOD-024-1	TBD

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months. The first verification for each applicable Facility under this standard must be a staged test.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date. Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 12 calendar months.

It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below.

If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability

verification. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU

transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator, if applicable.

3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature
- Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.

3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.

5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.

Note 1: Under some transmission system conditions, the data points obtained by the Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The Mvar limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

Note 4: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

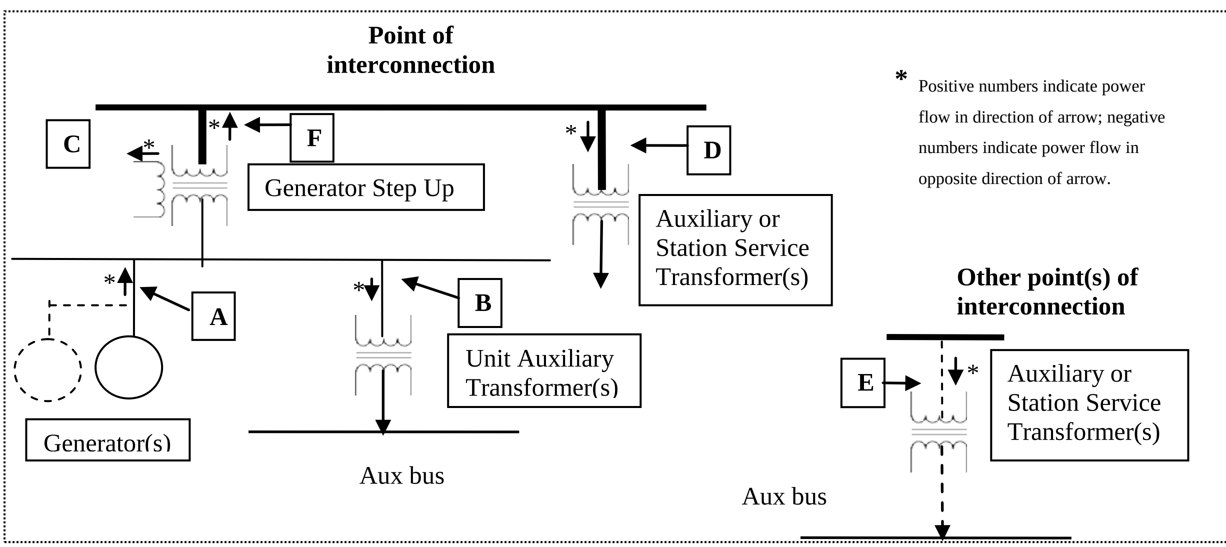
Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

Check all that apply:

- ☐ Over-excited Full Load Reactive Power Verification
- ☐ Under-excited Full Load Reactive Power Verification
- ☐ Over-excited Minimum Load Reactive Power Verification
- ☐ Under-excited Minimum Load Reactive Power Verification
- ☐ Real Power Verification
- ☐ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Reactive Power Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Voltage Ratio: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end of the verification period:

  Air temperature: _________

  Humidity: _________

  Cooling water temperature: _________

  Other data as applicable: _________

- Generator hydrogen pressure at time of test (if applicable) _____________

Date that data shown in last verification column in table above was taken _____________

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed (August 18, 2007).
5. First Draft of MOD-024-2 was posted for comment January 18 – February 18, 2010. MOD-024-2 was later combined with MOD-025-1 to form MOD-025-2.
6. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
7. Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.
8. ~~7.~~ Posted third draft of standard for 30-day concurrent formal comment period and initial ballot September 28 – October 31, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 30-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. Develop responses to comments and develop third version draft standard.~~	~~April - July 2012~~
~~2. Post response to comments and conduct successive ballot.~~	~~October-November 2012~~
~~3. Develop responses to ballot comments.~~	~~December 2012 – January 2013~~
1~~4~~. Post responses to comments and conduct recirculation ballot.	December ~~February~~ 2012~~3~~
1~~5~~. BOT adoption.	February~~March~~ 2013
1~~6~~. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. **Number:** MOD-025-2

3. **Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities:

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required[1]:

5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required[2]:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Note: The verification percentage above is based on the number of applicable units owned.

[2] Wind ~~F~~farm ~~V~~verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Requirements

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units, and ~~shall verify~~(ii) the Reactive Power capability of its synchronous condenser units~~ in accordance with Attachment 1~~.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units~~ in accordance with Attachment 1~~.

3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or(ii) the date the data is selected for verification using historical operational data.

B. Measures

M1. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R1.

M2. Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, or dated information collected and used to complete attachments and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R2.

M3. Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing 1 to less than or equal to 33 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~.~~ OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing more than 33 to 66 percent of the data.	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data. OR	The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data. OR The Generator Owner failed to verify the Real Power capability, per Attachment 1 of an applicable generating unit. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item

	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R2	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the Reactive	The Generator Owner verified and recorded the Reactive Power

	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~from the date of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR	Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~from the date of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Generator Owner performed the Reactive	Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~of the date of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Generator Owner performed the Reactive Power verification per Attachment 1,	capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~from the date of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Generator Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months.

	The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	"Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	OR The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.
R3	The Transmission Owner verified and recorded the Reactive Power capability	The Transmission Owner verified and recorded the Reactive Power capability of	The Transmission Owner verified and recorded the Reactive Power capability of	The Transmission Owner verified and recorded the Reactive Power capability of its applicable

	of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~from the date the of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data. OR The Transmission Owner	its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~from the date of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data. OR The Transmission Owner performed the Reactive	an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~of the date of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data. OR The Transmission Owner performed the Reactive Power verification per Attachment 1,	synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~from the date of verification by staged test or the date of the historical operating data that was selected for verification.~~ OR The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit. OR The Transmission Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months. OR The Transmission Owner performed

	performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.	Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.	"Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months. OR The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.	the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15calendar months.

D. Regional Variances

None

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
Version 1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3. 8. Removed the word "less" after 94% in section 3.4. Level 4.	01/20/06
Version 2	TBD	Revised per SAR for Project 2007-09 and combined with MOD-024-1	TBD

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months. The first verification for each applicable Facility under this standard must be a staged test.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date. Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 12 calendar months.

It is intended that Real Power testing be performed at the same time as full ~~Load~~ load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below.

If the Reactive Power capability is verified through test, ~~the Generator Owner shall schedule the test with its Transmission Operator. The test shall~~ it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification~~ (see Note 3 if the automatic voltage regulator is not available)~~. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification ~~shall~~ will be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU

transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator, if applicable.

3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature
- Other data as determined to be applicable by the Generator Owner to perf~~r~~orm corrections for ambient conditions.

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.

3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary ~~L~~load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.

5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions~~, can be determined~~. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.

Note 1: Under some transmission system conditions, the data points obtained by the Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The Mvar limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

~~Note 3: It is desired that the automatic voltage regulator be in service when testing a generator's reactive capability. If an automatic voltage regulator is not installed on the unit to be tested, or is not available at the time of the test, exercise extra caution not to exceed the operating limits of the generator.~~

Note 3~~4~~: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

Note 4~~5~~: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

Check all that apply:

☐ Over-excited Full Load Reactive Power Verification

☐ Under-excited Full Load Reactive Power Verification

☐ Over-excited Minimum Load Reactive Power Verification

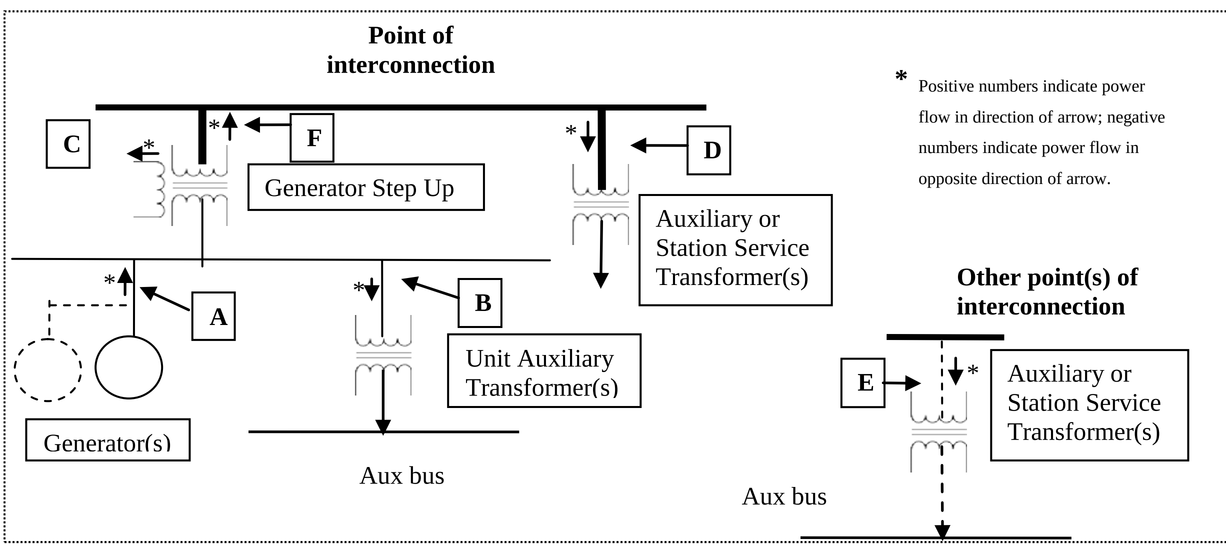
☐ Under-excited Minimum Load Reactive Power Verification

☐ Real Power Verification

☐ Staged Test Data

☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Reactive Power Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________,Verification Start Time _____, Verification End Time ______
- Scheduled Voltage ______________
- Transformer Voltage Ratio: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end of the verification period:

  Air temperature: _________

  Humidity: _________

  Cooling water temperature: _________

  Other data as applicable: _________

- ~~The recorded Mvar values were adjusted to rated generator voltage, where applicable.~~
- Generator hydrogen pressure at time of test (if applicable) _____________

Date that data shown in last verification column in table above was taken _____________

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

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Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Approvals Required

MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Transmission Owner that owns synchronous condenser(s)

Facilities

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO

governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.

- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

In those jurisdictions where regulatory approval is not required:

- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20 percent of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20 percent annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

It is the intent of *ReliabilityFirst* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the *ReliabilityFirst* Reliability Standards Development Procedure will be followed for any such revisions or retirements.

Retirements

MOD-024-1 - Verification of Generator Gross and Net Real Power Capability and MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability should both be retired at midnight of the day immediately prior to the Effective Date of MOD-025-2 in the particular jurisdiction in which the new standard is becoming effective.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Approvals Required

MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Transmission Owner that owns synchronous condenser(s)

Facilities

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the next calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO

governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.

- By the first day of the next calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

In those jurisdictions where regulatory approval is not required:

- By the first day of the next calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable units.
- By the first day of the next calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable units.
- By the first day of the next calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable units.
- By the first day of the next calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

The Implementation Plan phasing proposed is designed to allow large entities with dozens of units requiring verification an adequate amount of time to obtain resources and conduct testing to become fully compliant with standard requirements. The phase in period is set at five years with expectation at least 20 percent of an entities' applicable units will be verified annually with full compliance achieved by the end of the five year period. The 20 percent annual increment threshold was also selected to ensure that small entities with few units have incentive to become fully compliant in a timely manner and not delay verification of its applicable units until the fifth year of the phasing period.

Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

It is the intent of *ReliabilityFirst* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the *ReliabilityFirst* Reliability Standards Development Procedure will be followed for any such revisions or retirements.

Retirements

MOD-024-1 - Verification of Generator Gross and Net Real Power Capability and MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability should both be retired at midnight of the day immediately prior to the Effective Date of MOD-025-2 in the particular jurisdiction in which the new standard is becoming effective.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.
7. Posted second draft of standard for 30-day concurrent formal comment period and successive ballot September 28 – October 31, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. BOT adoption.	February 2013
2. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

2. **Number:** MOD-027-1

3. **Purpose:** To verify that the turbine/governor and load control or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an "applicable unit" that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

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[1] Turbine/governor and load control or active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

5. Effective Date:

5.1. For Requirements R1, and R3 through R5, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of turbine/governor and load control or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) models.

R2. Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both. Each verification shall include the following:

2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response for either:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 Note 1 with the applicable unit on-line,
- A speed governor reference change with the applicable unit on-line, or
- A partial load rejection test,[2]

2.1.2. Type of governor and load control or active power control/frequency control[1] equipment,

[2] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply

2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer),

2.1.4. Model structure and data for turbine/governor and load control or active power/frequency control, and

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit.

- Written notification, from its Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control or active power/frequency control model is not "usable,"
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[3] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[4] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic[5]. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Transmission Planner shall provide a written response to the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with

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[3] If verification is performed, the 10 year period as outlined in MOD-027 Attachment 1 is reset.

[4] Ibid.

[5] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

Requirement R2 that the model is usable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable.

5.1. The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,

5.2. A no-disturbance simulation results in negligible transients, and

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instruction or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 180 calendar days of making changes.

M5. Evidence of Requirement R5 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and for a model that is not useable, a technical description is the model is not usable, and dated evidence of transmittal (e.g., electronic mail messages, postal receipts, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1; OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1; OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice; OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that altered the equipment response characteristic.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information;	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information; OR The Transmission Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information; OR The Transmission Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information; OR The Transmission Planner provided a written response without including confirmation of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control or active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307

2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005

3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004

4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004

5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004

6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

7) P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 10year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 2).
3	Applicable unit is not subjected to a frequency excursion per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit's real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit's real power response as expected.
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
5	Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location; AND Each applicable unit has the same MVA nameplate rating; AND The nameplate rating is ≤ 350 MVA; AND Each applicable unit has the same components and settings; AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
6	The Generator Owner has submitted a verification plan. (Requirement R3 or R4)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.
8	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10 calendar year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action

NOTES:

NOTE 1: Unit model verification frequency excursion criteria:

- $\geq$ 0.05 hertz deviation (nadir point) from scheduled frequency for the Eastern Interconnection with the applicable unit operating in a frequency responsive mode
- $\geq$ 0.10 hertz deviation (nadir point) from scheduled frequency for the ERCOT and Western Interconnections with the applicable unit operating in a frequency responsive mode
- $\geq$ 0.15 hertz deviation (nadir point) from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode

NOTE 2: Establishing the recurring ten year unit verification period start date:

- The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 3: Consideration for early compliance:

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a 10 year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted (July 5, 2007).
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Posted second draft of standard for 45-day concurrent formal comment period and initial ballot February 29 – March 16, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 45-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to ballot comments.	April - July 2012
2. Post response to comments and third version draft revision of standard for 30-day comment and successive ballot period.	October - November 2012
3. Develop responses to ballot comments.	December 2012 – January 2013
4. Post responses to comments and conduct recirculation ballot.	February 2013
5. BOT adoption.	March 2013
6. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

2. **Number:** MOD-027-1

3. **Purpose:** To verify that the turbine/governor and load control or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an "applicable unit" that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

[1] Turbine/governor and load control or active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.

b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

5. Effective Date:

5.1. For Requirements R1, and R3 through R5~~6~~, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ~~thirty~~ that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Planner shall provide ~~one or more of~~ the following ~~to its requesting~~ requested information to the Generator Owner within 90 calendar days of receiving a written request: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Instructions on how to obtain the list of turbine/governor and load control or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) models.

R2. Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification ~~of~~ for~~an~~ individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or ~~plant~~ aggregate unit model(s) or both. Each verification shall include the following:

2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response for either:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 Note 1 with the applicable unit on-line,
- A speed governor reference change with the applicable unit on-line, or
- A partial load rejection test,[2]

2.1.2. Type of governor and load control or active power control/frequency control[1] equipment,

[2] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply

2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer),

2.1.4. Model structure and data for turbine/governor and load control or active power/frequency control, and

2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R3. Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit.

- Written notification, from its Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control or active power/frequency control model is not "usable,"
- Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or
- Written comments and supporting evidence from its Transmission Planner indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[3] (in accordance with Requirement R2). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R4. Each Generator Owner shall provide revised model data or plans to perform model verification[4] (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic[5]. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R5. Each Transmission Planner shall provide a written response to~~notify~~ the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with

[3] If verification is performed, the 10 year period as outlined in MOD-027 Attachment 1 is reset.

[4] Ibid.

[5] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

Requirement R2 that the model is usable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable~~; and shall include a technical description if the model is not usable that includes the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~.

5.1. The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,

5.2. A no-disturbance simulation results in negligible transients, and

5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instruction or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.

M2. The Generator Owner must have and provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 180 calendar days of making changes.

M5. Evidence of Requirement R5 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and for a model that is not useable, a technical description is the model is not usable, and dated evidence of transmittal (e.g., electronic mail messages, postal receipts, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 90 calendar days late; OR The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1; OR The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.	The Generator Owner provided its verified model(s) more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1; OR The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1; OR The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice; OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that altered the equipment response characteristic.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information;	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information; OR The Transmission Planner's written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information; OR The Transmission Planner's written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.	The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information; OR The Transmission Planner provided a written response without including confirmation of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control or active power/frequency control system functionality, modeling, and testing.

1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES General Meeting 2007, paper 07GM1307

2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005

3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004

4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004

5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004

6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

7) P. Pourbeik, C. Pink and R. Bisbee, "Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data", Proceedings of the IEEE PSCE, March, 2011

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 10year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 2).
3	Applicable unit is not subjected to a frequency excursion per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit's real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit's real power response as expected.
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

MOD-027 Attachment 1

Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity

Row Number	Verification Condition	Required Action
5	Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location; AND Each applicable unit has the same MVA nameplate rating; AND The nameplate rating is ≤ 350 MVA; AND Each applicable unit has the same components and settings; AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
6	The Generator Owner has submitted a verification plan. (Requirement R3 or R4)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.
8	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 10 calendar year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.

MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Unit model verification frequency excursion criteria:

- ≥ 0.05 hertz deviation (nadir point) from scheduled frequency for the Eastern Interconnection with the applicable unit operating in a frequency responsive mode
- ≥ 0.10 hertz deviation (nadir point) from scheduled frequency for the ERCOT and Western Interconnections with the applicable unit operating in a frequency responsive mode
- ≥ 0.15 hertz deviation (nadir point) from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode

NOTE 2: Establishing the recurring ten year unit verification period start date:

- The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 3: Consideration for early compliance:

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a 10 year period from the actual transmittal date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Conforming Changes to Other Standards
None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following Board of Trustees adoption.

- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Approvals Required

MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Planner

For the purpose of this standard, the following Facilities are considered, "applicable units." Units or plants that meet the following:

Generating units connected to the Eastern or Quebec Interconnections with the following characteristics:

- Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 100 MVA (gross aggregate rating).

Generating units connected to the Western Interconnection with the following characteristics:

- Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Generating units connected to the ERCOT Interconnection with the following characteristics:

- Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the Bulk Electric System.
- Each generating plant or generating Facility consisting of multiple units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate rating).

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

In those jurisdictions where no regulatory approval is required:

- Each responsible entity shall ensure compliance with Requirements R1, and R3 through R5 by the first day of the first calendar quarter following Board of Trustees adoption.

- Each Generator Owner shall ensure at least 30 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, four years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 50 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, six years following Board of Trustees adoption.
- Each Generator Owner shall ensure at least 100 percent of its applicable unit gross MVA per Interconnection are compliant with Requirement R2 by the first day of the first calendar quarter, 10 years following Board of Trustees adoption.

Justification

This phased implementation supports the ten year cycle for the collection of generator response data necessary for required verifications and typical generating unit outage schedules, and it also provides ample time for Generator Owners to either purchase new recording equipment as required or to make necessary modifications to existing recording equipment (frequency triggers, length of recordings for frequency excursions, additional event storage capacity, etc).

Consideration for Early Compliance

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a ten year period from the actual verification date if either of the following applies:

- The Generator Owner has a verified model that is compliant with the applicable regional entity policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner has an existing verified model that is compliant with the requirements of this standard.

Retirements

None

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Draft 2 of PRC-019-1 was posted for a 45 day concurrent comment and ballot period from February 29 – April 16, 2012.
7. Draft 3 of PRC-019-1 was posted for a 30 day concurrent comment and ballot period from September 28 – October 31, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 30-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post responses to comments and conduct recirculation ballot.	December 2012
2. BOT adoption.	February 2013
3. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-1

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

   5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each

Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[1] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar

	years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,”Protective Relaying For Power Generation Systems”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

“Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

“IEEE C37.102-2006 IEEE Guide for AC Generator Protection”

“IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above”

Version History

Version	Date	Action	Change Tracking

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

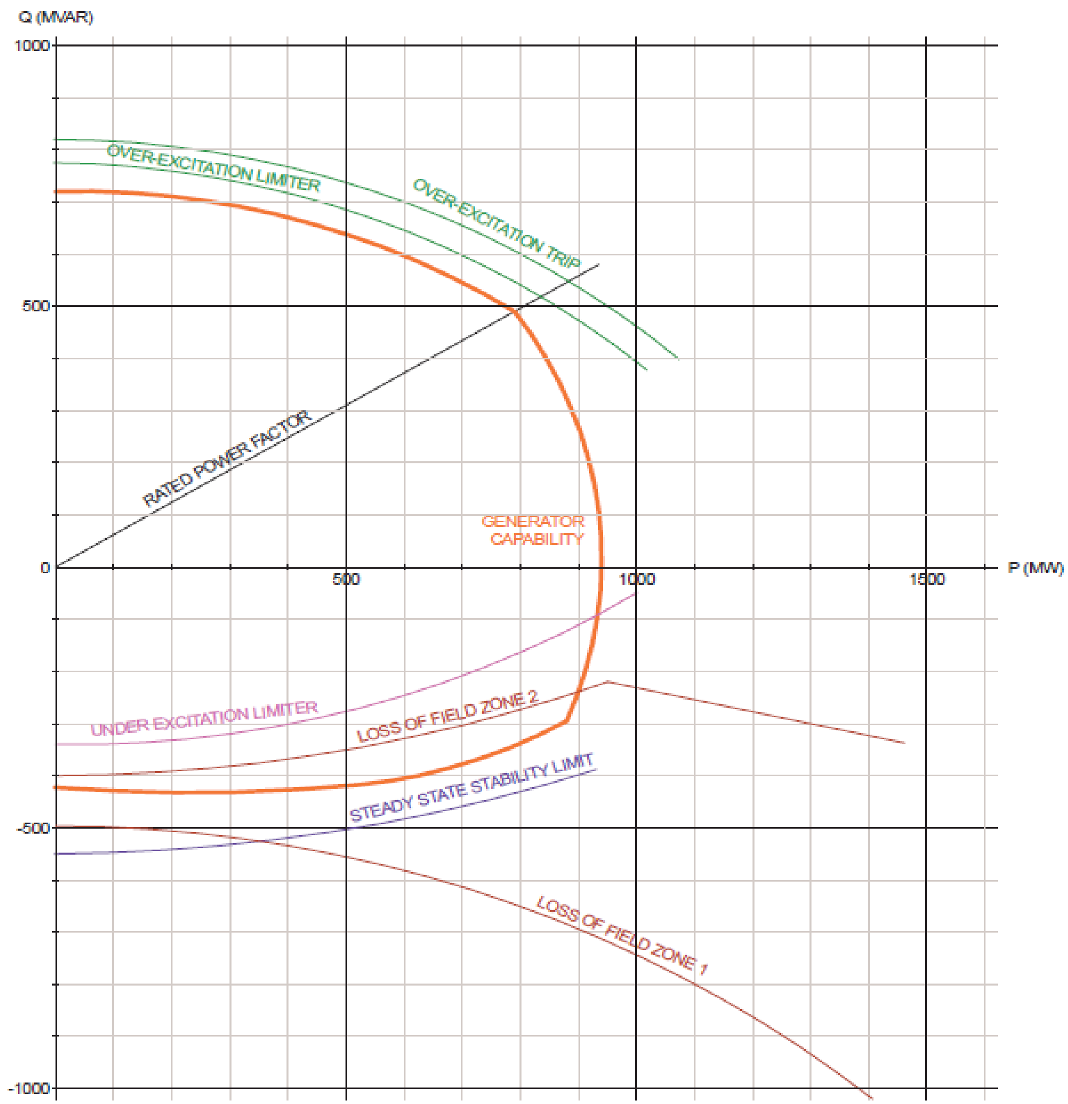
On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$
$$R = V^2_g/2*(1/X_s+1/X_d)$$

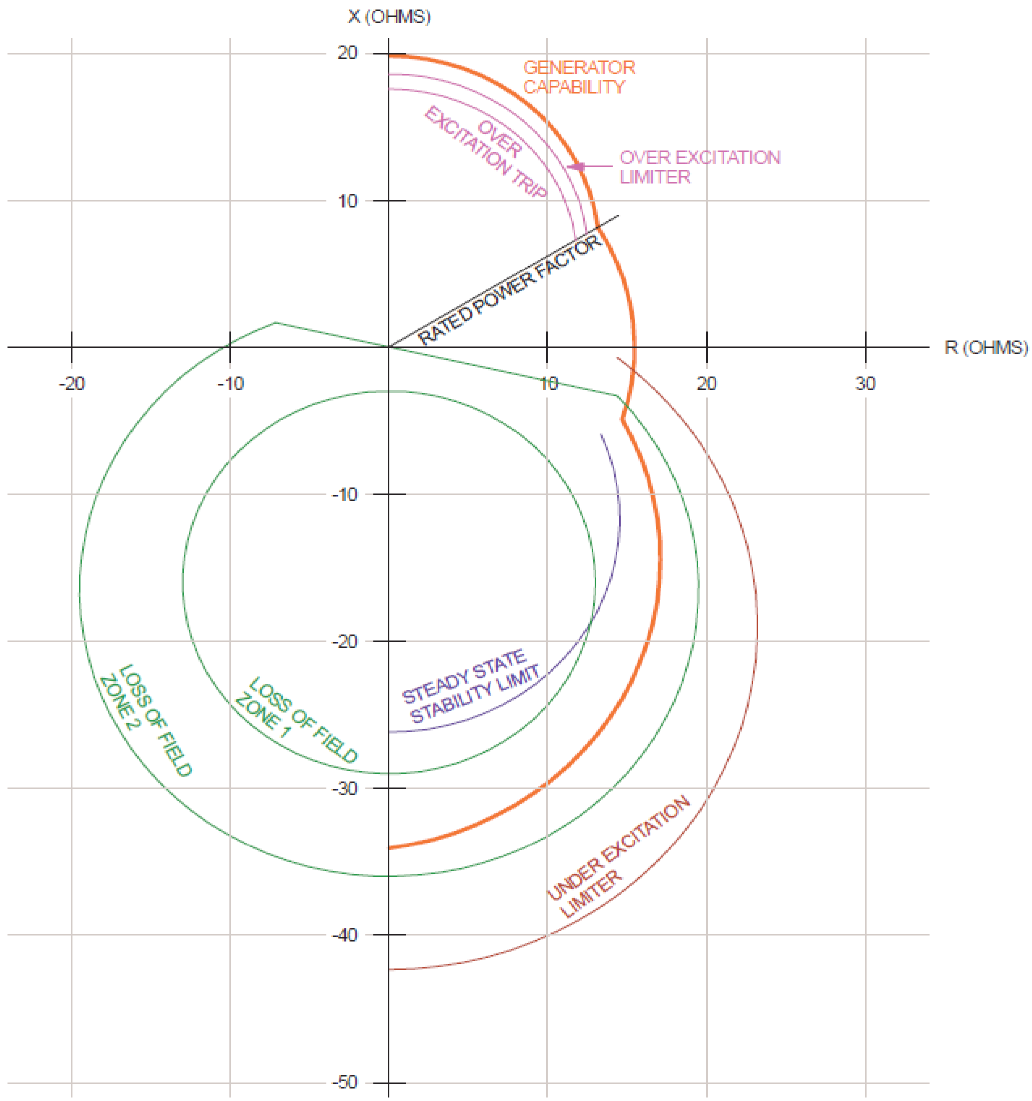
On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

$$C = (X_d-X_s)/2$$
$$R = (X_d+X_s)/2$$

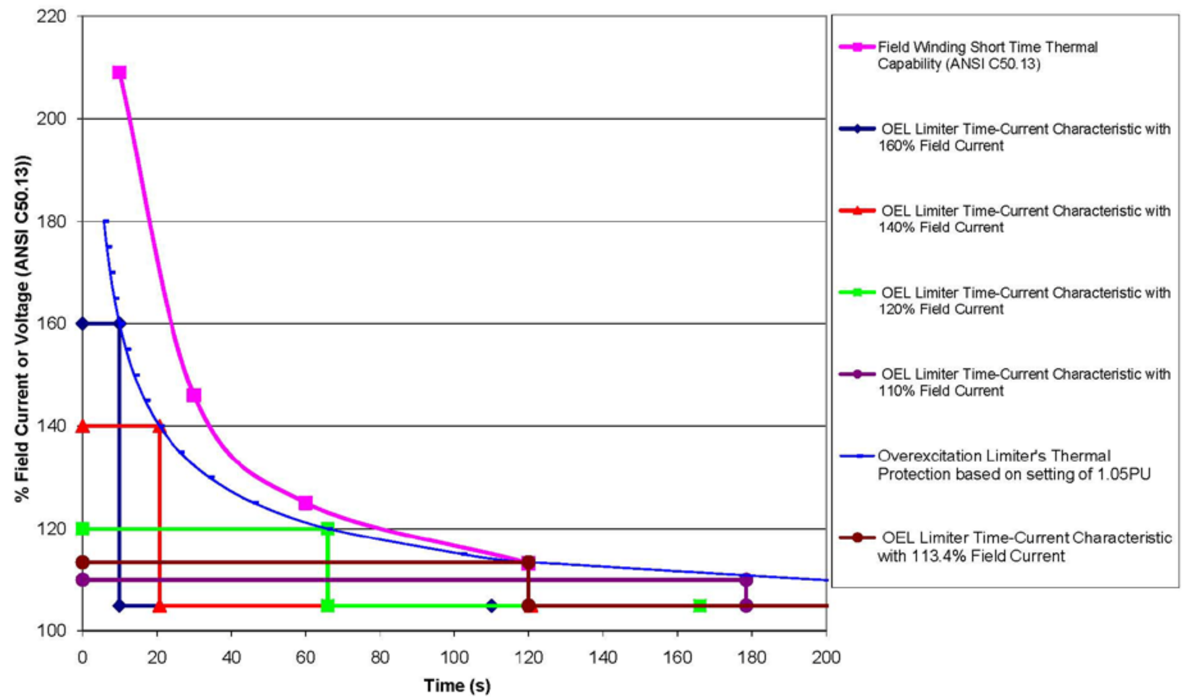
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Posted first draft of standard for a 30 day comment period June 15 –July 15, 2011
6. Draft 2 of PRC-019-1 was posted for a 45 day concurrent comment and ballot period from February 29 – April 16, 2012.
~~6.~~ Draft 3 of PRC-019-1 was posted for a 30 day concurrent comment and ballot period from September 28 – October 31, 2012.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed standard including Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels; and is being submitted for a 30-day concurrent formal comment period and successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. Develop responses to comments and develop third version draft standard.~~	~~April - July 2012~~
~~2. Post response to comments and conduct successive ballot.~~	~~October-November 2012~~
~~3. Develop responses to ballot comments.~~	~~December 2012 – January 2013~~
1~~4~~. Post responses to comments and conduct recirculation ballot.	~~February~~ December 2012~~3~~
5. BOT adoption.	~~March~~ February 2013
6. File with regulatory authorities.	April 2013

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
2. **Number:** PRC-019-1
3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.
4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each

Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service~~-~~[1] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator ~~AVR~~ control loop and ~~system~~ steady-state system operating conditions, verify the following coordination items for each applicable Facility:

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable~~,~~ in-service Protection System devices are set to operate to ~~,~~ isolate or de-energize equipment~~,~~ in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes
- Protection System settings or component changes
- Generating or synchronous condenser equipment capability changes, or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service~~-~~[2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination ~~review~~ required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar

	years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

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"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking

G. **Reference**

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Section G Attachment 1), or
- R-X Diagram (Example in Section G Attachment 2), or
- Inverse Time Diagram (Example in Section G Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.
- ~~Converter over-temperature limiter and associated protection function.~~

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the “infinite bus” including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2{}_g/2*(1/X_s-1/X_d)$$

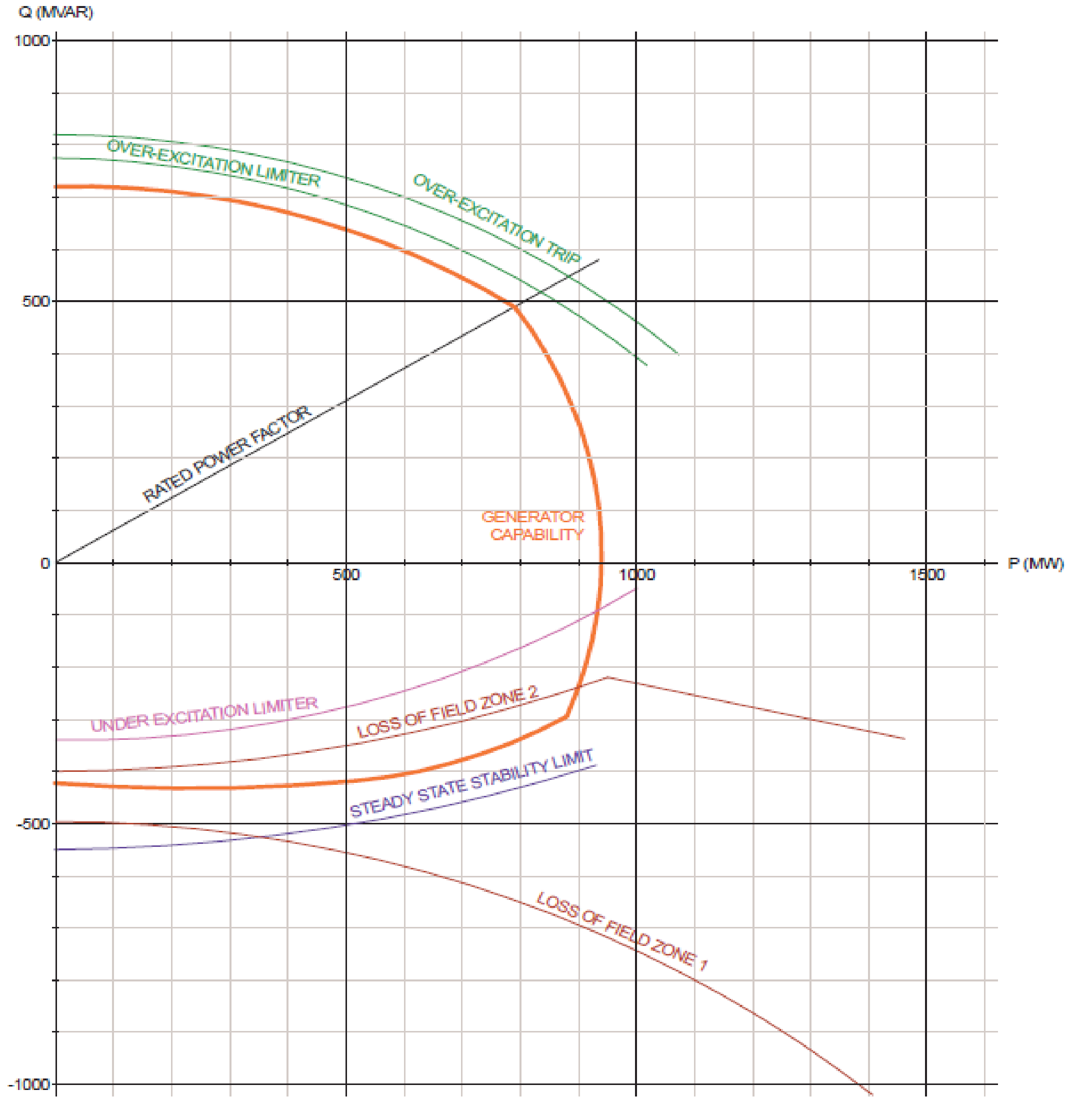
$$R = V^2{}_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the “infinite bus” including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

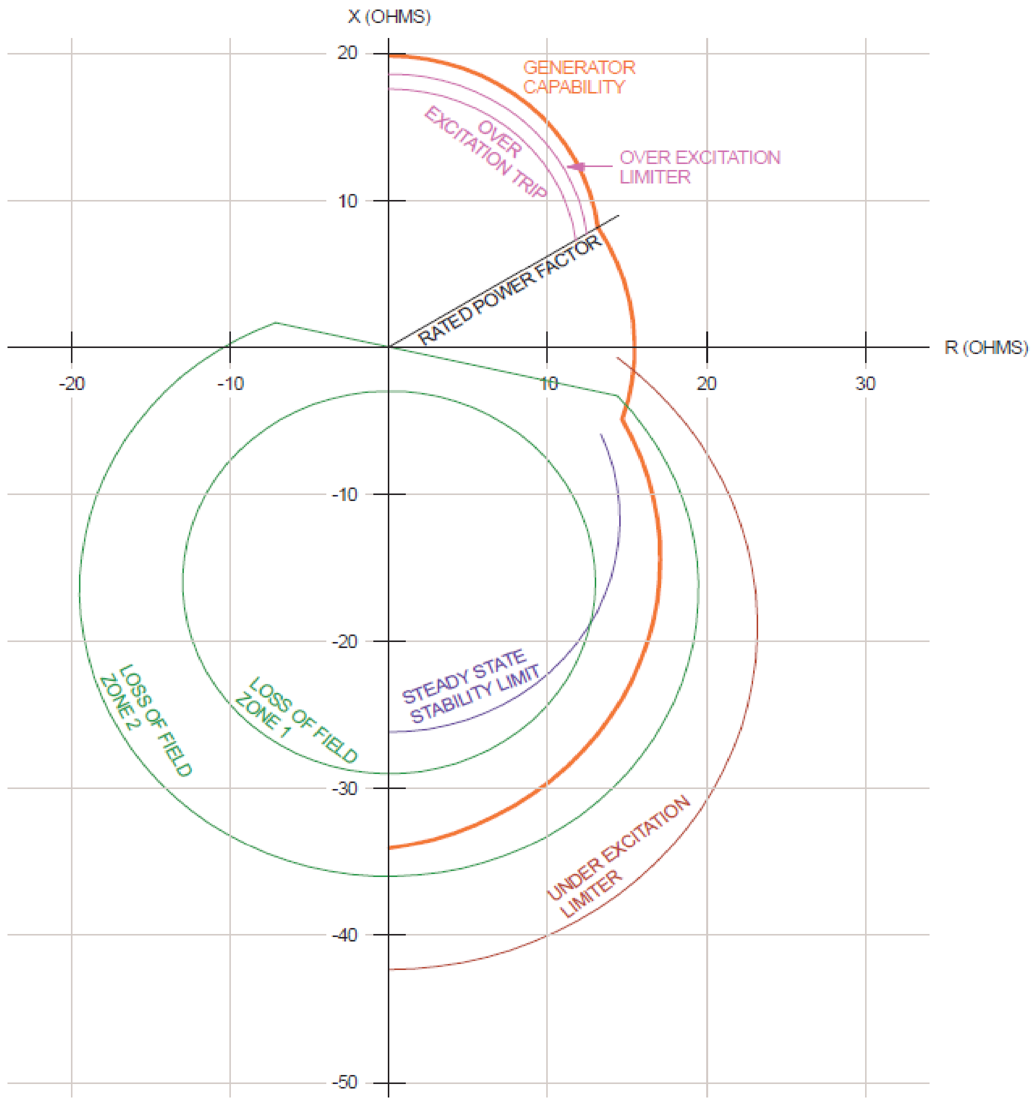
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

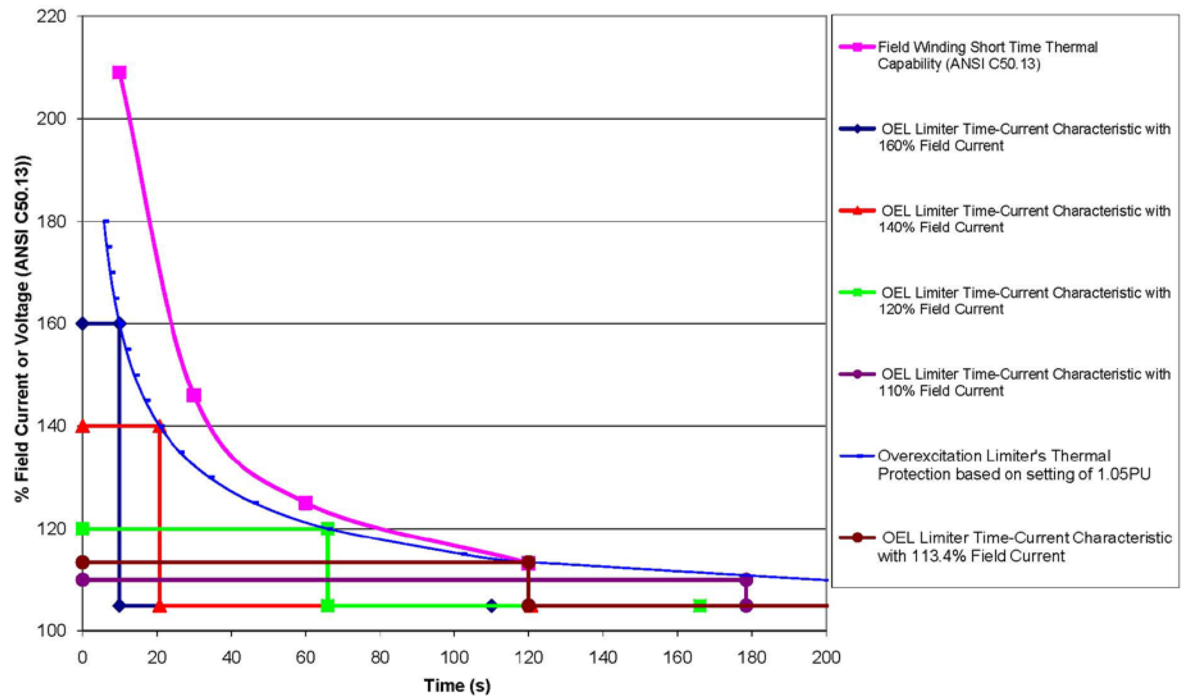
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Approvals Required

PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner that owns synchronous condenser(s)

Applicable Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any of the following:

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System;
- Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System;
- Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating);
- Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

Conforming Changes to Other Standards
None

Effective Dates
PRC-019-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.
- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
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- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Justification for Phasing:

The coordination activities in this standard (PRC-019-1) are most effectively performed just prior to the performance of a reactive capability test, as required by MOD-025-2. Hence, the SDT has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2.

Retirements

None

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Approvals Required

PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner
Transmission Owner that owns synchronous condenser(s)

Applicable Facilities

For the purpose of this standard, the term, “applicable Facility” shall mean any ~~one~~ of the following:

- Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System;~~.~~
- Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System;~~.~~
- Generating plant/Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating);~~.~~
- Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator’s restoration plan.

Conforming Changes to Other Standards
None

Effective Dates
PRC-019-1 shall become effective as follows:

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.
- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval,~~,~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.
- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval,~~,~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.
- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval,~~,~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval,~~,~~, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Justification for Phasing:

The coordination activities in this standard (PRC-019-1) are most effectively performed just prior to the performance of a reactive capability test, as required by MOD-025-2. Hence, the SDT has followed the same implementation schedule in PRC-019-1 as defined in MOD-025-2.

Retirements

None

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-026-1 — Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-026-1:
There are six requirements in MOD-026-1. Four requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-026-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This requirement is administrative in nature for providing instructions and data used for performing model verification. The “Lower” VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The “Medium” VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R6; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-027-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to provide a written response after receiving a request. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-026-1, Requirement R6:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R6 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify either an Operations Planning or a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-027-1 Requirement R5 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to

effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R6 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-026-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for MOD-026-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is timely. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness with completeness of information required for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R5:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating equal multiple parts criteria VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts also incorporate increments for tardiness consideration. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-026-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium-risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could; under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium-risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control; or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup Facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and Facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical Facilities
- Appropriate use of transmission Loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4; whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for MOD-025-2:

There are three requirements in MOD-025-2. Each requirement was assigned a "Medium" VRF.

VRF for MOD-025-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each Requirement in MOD-025-1 is assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirements R2 and R3. Each requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC's definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R2:

- FERC Guideline 2 — Consistency within is similar in scope to Requirements R1 and R3. Each Requirement is to perform a verification of capability.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 in concept, and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit as specified in this standard.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R1 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

VRF for MOD-025-2, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. Each requirement in MOD-025-1 is assigned a “Medium” VRF. Requirement R3 is similar in scope to Requirements R1 and R2.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is similar with MOD-010-0 and MOD-012-0, Requirements R1 and R2, in concept and they have approved Medium VRFs. A primary difference being MOD-010-0 and MOD-012-0 require data submission for all Facilities, and not merely a single unit, as specified in this standard.
- FERC Guideline 4 — Consistency with NERC’s definition of the VRF level selected exists. Failure to verify models in the long-term planning time horizon is a requirement in a planning time frame that, if violated, could, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. Therefore, the assigned “Medium” VRF is appropriate.

- FERC Guideline 5 — Treatment of requirements that co-mingle more than one obligation is satisfactory. The Requirement R3 risk objective is to verify capability. The risk objectives are administrative in nature, consisting of recording and submission requirements for planning studies. The “Medium” VRF assigned is based on the risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-025-2 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for MOD-025-2 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms, and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action, and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation, and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-025-2 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions.	Standard requirements have been significantly revised since MOD-025-1 was approved. Proposed VSL's are binary with additional consideration for the obligation to submit information in a timely fashion; whereas, MOD-025-1 levels of noncompliance only considered completeness of submitted information. As drafted, proposed VSL's raise the current level of compliance.	Proposed VSL's identify noncompliance based on the obligation to verify capability and provide data within certain timeframes. The VSLs account for increments of tardiness and incomplete data submissions. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance and obligation information submission timeliness.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information is provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for MOD-027-1:

There are five requirements in MOD-027-1. Three requirements were assigned a "Lower" VRF while the remaining two were assigned a "Medium" VRF.

VRF for MOD-027-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-004-1, Requirement R9 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R1 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide requested information is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 high risk objective is to provide requested information. This

requirement is administrative in nature for providing instructions and data used for performing model verification. The “Lower” VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 which have an approved VRF of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R2 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 high risk objective is to verify models per specified periodicity. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation, information revision obligation and submission requirements. The “Medium” VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 does not contains Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R7 and R8 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R3 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or

capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 high risk objective is to provide a written response after receiving notice. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations include actions similar in scope to actions specified in Requirement R1 and R5; and all standard requirements specify a Long-term Planning Time Horizon.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar to MOD-004-1, Requirement R1 and R2 that has an approved Lower VRF. This requirement is also similar to draft standard MOD-026-1 Requirement R4 which also specifies a Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify models in the Long-term Planning Time Horizon is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 high risk objective is to provide revised data after making changes to equipment. The Requirement is administrative in nature consisting of documentation, information revision obligation and submission requirements. The "Lower" VRF assigned is based on the high risk objective specified.

VRF for MOD-027-1, Requirement R5:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R5 contains Parts specifying supporting obligations for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part represents an obligation for ensuring main requirement completeness. Requirement obligations include actions similar in scope to actions specified in Requirement R1; and all standard requirements specify a Long-term Planning Time Horizon.

- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar with MOD-010-0 and MOD-012-0 Requirements R1 and R2 that have approved VRFs of Medium. This requirement is also similar to draft standard MOD-026-1 Requirement R6 which also specifies a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to identify if a model is useable or not is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R5 high risk objective is to verify if the model is useable or not. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of documentation and submission requirements. The "Medium" VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in MOD-027-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for MOD-027-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is timely. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s consider completeness of listed parts deemed to possess equal reliability weight and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is complete. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R3:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. Actions and obligations specified in the Requirement Parts incorporate a binary element, consideration for omitting required information. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of a binary element and increments for tardiness. Binary requirements are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete and provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R4:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the main Requirement action. The SDT has determined a 30 day “Increments for Tardiness” period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL’s utilize increments for tardiness rationale. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the actions and obligations specified.	Proposed VSL’s do not expand on what is required in the requirement. The VSL’s assigned only consider performing required action and if information submission is complete and provided in a timely manner. Proposed VSL’s are consistent with the requirement.	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

VSLs for MOD-027-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness VSL elements for the Main Requirement action. Actions specified in the Requirement Parts incorporate completeness of the actions and obligations specified. The SDT has determined a 30 day "Increments for Tardiness" period is appropriate for standard VSLs proposed.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of completeness of listed parts and also increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action and if information submission is both complete provided in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-019-1:
There are two requirements in PRC-019-1 and both have been assigned a "Medium" VRF.

VRF for PRC-019-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R1 is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to periodically verify voltage regulation controls, limiters and protection coordinated with unit

and synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.

- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 and Part 1.1 have a reliability objective to verify voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-019-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirements R1 and R2 specify that the responsible entity must verify coordination for applicable Facilities. The standard requirements specify a Long-term Planning Time Horizon and both are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. Requirement R2 is similar in concept with both PRC-010-0 Requirement R1 and PRC-014-0 Requirement R1, both of which require 5-year verification of protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-019-1 apply to a single unit, synchronous condenser or plant. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to verify coordination following setting changes affecting unit or synchronous condenser coordination in the Long-term Planning Time Horizon is a requirement that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 has a high reliability objective to specify the periodicity for verifying voltage regulation controls, limiters and protection coordinated with unit and synchronous condenser coordination following a change to equipment settings. Failure to verify the coordination for a single applicable Facility is unlikely to, under emergency, abnormal,

or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. . The “Medium” VRF assigned is based on the high risk objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-019-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for PRC-019-1 Requirement R1:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	The proposed VSLs are based on increments of tardiness for completing the required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider performing required action per the procedure specified by listed parts. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-019-1 Requirement R2:

R#	Compliance with NERC Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by identifying noncompliance based on the obligation to verify coordination within a certain timeframe. VSLs account for increments of tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSLs are based on increments of tardiness for competing required verifications. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and completeness of the actions and obligations specified.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider performing required action per the procedure specified by listed parts. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval. The confusion centers on “approval” and when the 30-day period starts. 1311. We repeat our concern that Requirement R2, which specifies that the “regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval,” is not clear. The requirement lacks a definition of what approval is required and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement.	MOD-024-1; FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		operational data. R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 2.1. Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units. 2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data. R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 3.1. Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.
Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions can be determined. 1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power	MOD-024-1; FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner, including test conditions. Section 3 of Attachment is: 3. Record the following data for the verifications specified above: 3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period. 3.2. The voltage schedule provided by the Transmission Operator, if applicable. 3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary. 1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should		3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as: • Ambient air temperature • Relative humidity • Cooling water temperature • Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.3.5.The date and time of the verification period, including start and end time in hours and minutes. 3.6. The existing GSU and/or system Interconnection transformer(s) voltage ratio and tap setting. 3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer. 3.8. Whether the test data is a result of a staged test or if it is operational data.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
be reviewed in the ERO Reliability Standards development process.		
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
Remove the fill-in-the-blank aspects (correct reference to "…Regional Reliability Organization's procedures…").	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Goal is uniform North American standards for real and reactive power verification. Look at regional requirements and identify the best practice, commonalities and differences, and whether differences are needed for reliability.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
No requirement for the RRO to demonstrate that its procedures result in accurate information of gross and net real power capability of generators for steady state models	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit	MOD-024-1; Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
Provide clarity where the Planning Authority is mentioned	MOD-024-1, Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.
Require verification of reactive power capability at multiple points over a unit's operating range. 1321. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW loading. However, other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available	MOD-025-1, FERC Order 693	Attachment 1 of MOD-025-2 addresses this directive. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.		shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data: 2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications. 2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure. 2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval. The confusion centers on “approval” and when the 30-day period starts.	MOD-025-1, FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
1322. We maintain the concern we expressed in the NOPR that Requirement R2 provides that the “regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval” and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.		Requirements R1, R2 and R3 above.
Remove the fill-in-the-blank aspects (correct reference to “… Regional Reliability Organization’s procedures…”).	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Refer to MOD-024.	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
These standards do not provide for uniform testing of generator capability. The determination of which units are tested, how frequently they are tested, and the criteria used for determining capability are left	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
to individual regions.		
R1.5.1: The benefit of verifying maximum capability of generators to absorb VArs at seasonal real power generation capability is unclear, particularly if this standard applies to virtually all generators. For the vast majority of units, the need to absorb VArs occurs during low-load conditions, when unit real power production is below maximum capability and the unit's ability to absorb VArs is greater. Therefore, the single datum for unit VAr absorption capability determined pursuant to this standard seems to be of little practical use, except for relatively few generators in a limited set of circumstances.	MOD-025-1, Phase III/IV Team	The Standard no longer references "seasonal capability." Attachment 1 of MOD-025-2 describes the required testing. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data: 2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications. 2.1.1 Verify synchronous generating unit's maximum real power

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		verification at minimum Real Power output. 2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure. 2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. Please see Requirements R1, R2 and R3 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit.	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
Severity of non-compliance should be based on the percentage of the generator owner's total generation capability comprised of units required to be verified, rather than on the percentage (number)	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
of generating units. Exempt units should be excluded from the total generation capability for determining level of non-compliance.		a requirement.
There is no clear reason for regional variations in capability testing. A generator in Georgia does not have more or less capability than an identical unit applied across the Florida line, despite the fact that one is in SERC and the other in FRCC.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard as well as regional variances have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Fundamental guidelines outlining some basic requirements (e.g., all units over 20 MW shall be tested annually under conditions that permit full net output of the unit for normal operation) are lacking.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. All required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Provide clarity where the Planning Authority is mentioned	MOD-025-1; Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval. The confusion centers on “approval” and when the 30-day period starts. 1311. We repeat our concern that Requirement R2, which specifies that the “regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval,” is not clear. The requirement lacks a definition of what approval is required and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement. ~~Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions~~	MOD-024-1; FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
~~can be determined.~~ ~~1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary.~~ ~~1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather~~		operational data. R2. Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 2.1. Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and ~~shall verify~~(ii) the Reactive Power capability of its synchronous condenser units ~~in accordance with Attachment 1~~. 2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data. R3. Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 3.1. Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
~~conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.~~		condenser units~~ in accordance with Attachment 1~~. 3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.
Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions can be determined. 1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The	MOD-024-1; FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner, including test conditions. Section 3 of Attachment is: 3. Record the following data for the verifications specified above: 3.1. The value of the gross Real and Reactive Power generating

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary. 1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate		capabilities at the end of the verification period. 3.2. The voltage schedule provided by the Transmission Operator, if applicable. 3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated. 3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as: • Ambient air temperature • Relative humidity • Cooling water temperature • • Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.3.5.The date and time of the verification period, including start and end time in hours and minutes. 3.6. The existing GSU and/or system Interconnection transformer(s) voltage ratio and tap setting. 3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.		GSU transformer. 3.8. Whether the test data is a result of a staged test or if it is operational data.
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
Remove the fill-in-the-blank aspects (correct reference to "…Regional Reliability Organization's procedures…").	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Goal is uniform North American standards for real and reactive power verification. Look at regional requirements and identify the best practice, commonalities and differences, and whether differences are needed for reliability.	MOD-024-1, Fill-in-the-blank team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
No requirement for the RRO to demonstrate that its procedures result in accurate information of gross and net real power capability of generators for steady state models	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-024-1; Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirements R1 and R2 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1 and R2 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit	MOD-024-1; Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
Provide clarity where the Planning Authority is mentioned	MOD-024-1, Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.
Require verification of reactive power capability at multiple points over a unit's operating range. 1321. We disagree with commenters that verifying	MOD-025-1, FERC Order 693	Attachment 1 of MOD-025-2 addresses this directive. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW loading. However, other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.		Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification~~ (see Note 3 if the automatic voltage regulator is not available).~~. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification ~~shall~~will be by another staged test, not operational data: 2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications. 2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.
Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval. The confusion centers on "approval" and when the 30-day period starts. 1322. We maintain the concern we expressed in the NOPR that Requirement R2 provides that the "regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval" and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.	MOD-025-1, FERC Order 693	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R2 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner must report the required data to its Transmission Planner. See Requirements R1, R2 and R3 above.
Remove the fill-in-the-blank aspects (correct reference to "… Regional Reliability Organization's procedures…").	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Refer to MOD-024.	MOD-025-1, Fill-	The GVSDT has combined MOD-024 and MOD-025 into a single

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	in-the-blank Team	standard, MOD-025-2.
Review MOD-024 and MOD-025 concurrently to transition to uniform North American standards	MOD-025-1, Fill-in-the-blank Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard, MOD-025-2.
These standards do not provide for uniform testing of generator capability. The determination of which units are tested, how frequently they are tested, and the criteria used for determining capability are left to individual regions.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
R1.5.1: The benefit of verifying maximum capability of generators to absorb VArs at seasonal real power generation capability is unclear, particularly if this standard applies to virtually all generators. For the vast majority of units, the need to absorb VArs occurs during low-load conditions, when unit real power production is below maximum capability and the unit's ability to absorb VArs is greater. Therefore, the single datum for unit VAr absorption capability determined pursuant to this standard seems to be of little practical use, except for relatively few generators in a limited set of circumstances.	MOD-025-1, Phase III/IV Team	The Standard no longer references "seasonal capability." Attachment 1 of MOD-025-2 describes the required testing. 2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification~~ (see Note 3 if the automatic voltage regulator is not available).~~. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification ~~shall~~will be by another staged test, not operational data: 2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications. 2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		during verifications. 2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure. 2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.
It is not clear in R3 to whom the Generator Owner will report the information.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. The original R3 from MOD-024 maps to Requirement R1 of the proposed MOD-025-2. Fill in the blank components of the standard have been eliminated and the Generator Owner

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		must report the required data to its Transmission Planner. Please see Requirements R1, R2 and R3 above.
Non compliance levels are too strict. A small utility with 15-20 units will be L4 noncompliant if they miss one unit.	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
Severity of non-compliance should be based on the percentage of the generator owner's total generation capability comprised of units required to be verified, rather than on the percentage (number) of generating units. Exempt units should be excluded from the total generation capability for determining level of non-compliance.	MOD-025-1, Phase III/IV Team	The Standard now utilizes Violation Risk Factors, Time Horizons and Violation Severity Levels. The issue is addressed through the CMEP. The standard is written such that each generator must be tested. Failure to test a single unit results in a single violation for a requirement.
There is no clear reason for regional variations in capability testing. A generator in Georgia does not have more or less capability than an identical unit applied across the Florida line, despite the fact that one is in SERC and the other in FRCC.	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. Fill in the blank components of the standard as well as regional variances have been eliminated and all required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.
Fundamental guidelines outlining some basic requirements (e.g., all units over 20 MW shall be tested annually under conditions that permit full net	MOD-025-1, Phase III/IV Team	The GVSDT has combined MOD-024 and MOD-025 into a single standard. All required testing and data information is contained in Attachment 1 of the proposed MOD-025-2.

Project 2007-09 Generator Verification — MOD-024 and MOD-025		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
output of the unit for normal operation) are lacking.		
Provide clarity where the Planning Authority is mentioned	MOD-025-1; Team Comments	The GVSDT has written the requirements such that the Transmission Planner receives the information from the Generator Owner.

A. Introduction

1. **Title:** **Verification of Generator Gross and Net Real Power Capability**

2. **Number:** MOD-024-1

3. **Purpose:** To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generation Owner.

5. **Effective Dates:**

   Requirement 1 and Requirement 2 **—** April 1, 2006.

   Requirement 3 — January 1, 2007.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:

- **R1.1.** Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.
- **R1.2.** Criteria for reporting generating unit auxiliary loads.
- **R1.3.** Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.
- **R1.4.** Periodicity and schedule of model and data verification and reporting.
- **R1.5.** Information to be verified and reported:
  - **R1.5.1.** Seasonal gross and net Real Power generating capabilities.
  - **R1.5.2.** Real power requirements of auxiliary loads.
  - **R1.5.3.** Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Real Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Real Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to those procedures, for verification and reporting of generator gross and net Real Power capability were provided to affected Generator Owners, Generator Operators,

Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Real Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous versions of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2, R1.4

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: There shall be a level two non-compliance if **both** of the following conditions are present:

2.2.1 Procedures did not meet two of the following requirements: R1.1, R1.2, R1.4

2.2.2 No evidence that procedures were distributed as required in R2.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet either R1.5.1, R1.5.2 or R1.5.3

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a generator owner's units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a generator owner’s units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a generator owner’s units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% of a generator owner’s units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06

A. Introduction

1. Title: **Verification of Generator Gross and Net Reactive Power Capability**

2. Number: MOD-025-1

3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.

4. Applicability

4.1. Regional Reliability Organization.

4.2. Generator Owner.

5. Effective Dates:

Requirement 1 and Requirement 2 — January 1, 2007

Requirement 3:

January 1, 2008 — 1st 20% compliant

January 1, 2009 — 2nd 20% compliant

January 1, 2010 — 3rd 20% compliant

January 1, 2011 — 4th 20% compliant

January 1, 2012 — 5th 20% compliant

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Criteria for reporting generating unit auxiliary loads.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.

R1.4. Periodicity and schedule of model and data verification and reporting.

R1.5. Information to be reported:

R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.

R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.

R1.5.3. Verified Reactive Power of auxiliary loads.

R1.5.4. Method of verification, including date and conditions.

R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the

Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Reactive Power capability in accordance with R1.

M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to these procedures, for verification and reporting of generator gross and net Reactive Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Reactive Power capability, consistent with that Regional Reliability Organization's procedures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

For Regional Reliability Organization: NERC.

For Generator Owner: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain both the current and previous version of the procedures.

The Generator Owner shall retain information from the most current and prior verification.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Regional Reliability Organization:

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 Procedures did not meet one of the following requirements: R1.1, R1.2 or R1.4.

2.1.2 No evidence that procedures were distributed as required in R2.

2.2. Level 2: Procedures did not meet two or three of the following requirements: R1.1, R1.2 or R1.4.

2.3. Level 3: Procedures did not meet R1.3.

2.4. Level 4: Procedures did not meet R1.5.1, R1.5.2, R1.5.3, or R1.5.4.

3. Levels of Non-Compliance for Generator Owner:

3.1. Level 1: Complete, verified generator data were provided for 98% or more but less than 100% of a Generator Owner’s units as required by the regional procedures.

3.2. Level 2: Complete, verified generator data were provided for than 96% or more, but less than 98% of a Generator Owner’s units as required by the regional procedures.

3.3. Level 3: Complete, verified generator data were provided for 94% or more, but less than 96% of a Generator Owner’s units as required by the regional procedures.

3.4. Level 4: Complete, verified generator data were provided for less than 94% less of a Generator Owner’s units as required by the regional procedures.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
Version 1	12/01/05	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3.	01/20/06

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Project 2007-09 Generator Verification
MOD-024-1 DRAFT Mapping Document

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-024-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Real Power Capability.	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability.
3. Purpose: To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.
R1. The Regional Reliability	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined. Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, Applicability**,** which follows the Registry Criteria.	**4.2 Facilities:** 4.2.1 For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**Requirement R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	**Requirement R1** references **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be performed.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		or (ii) the date the data is selected for verification using historical operational data.
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirement R1 references Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Real Power generating capabilities. **R1.5.2.** Real Power requirements of auxiliary loads.	**Requirement R1** references **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.5.3. Method of verification, including date and conditions.		containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test (ii) or the date the data is selected for verification using historical operational data.
R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Real Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.

Project 2007-09 Generator Verification
MOD-024-1 DRAFT Mapping Document

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-024-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Real Power Capability.	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability.
3. Purpose: To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.
R1. The Regional Reliability	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined. Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, Applicability**,** which follows the Registry Criteria.	**4.2 Facilities:** 4.2.1 For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**Requirement R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	**Requirement R1** references **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be performed.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		or (ii) the date the data is selected for verification using historical operational data.
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirement R1 references Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Real Power generating capabilities. **R1.5.2.** Real Power requirements of auxiliary loads.	**Requirement R1** references **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.5.3. Method of verification, including date and conditions.		containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test (ii) or the date the data is selected for verification using historical operational data.
R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Real Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R1**.	R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Verify the Real Power capability of its generating units

MOD-024-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-024-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		in accordance with Attachment 1. 1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.

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Project 2007-09 Generator Verification MOD-025-1 DRAFT Mapping Document

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-025-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Reactive Power Capability	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.
R1. The Regional Reliability Organization	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, **Applicability,** which follows the Registry Criteria.	**4.2 Facilities:** For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard. **Attachment 1,** section 4.1 allows engineering estimates in those situations where metering to measure a reactive load is not installed.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data,	**Requirements R2 and R3,** reference **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii)

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
commissioning data, performance tracking, and testing, etc.	performed.	the Reactive Power capability of its synchronous condenser units. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data
R1.4. Periodicity and schedule of model	**Requirements R2 and R3,**	**R2.** Each Generator Owner shall provide its Transmission Planner

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
and data verification and reporting.	reference **Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Reactive Power generating capabilities while at the Seasonal Real Power generating capability as reported in accordance with MOD-024-2. **R1.5.2.** Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc. **R1.5.3** Verified Reactive Power of Auxiliary loads.	**Requirements R2 and R3,** reference **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium]

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.5.4. Method of verification, including date and conditions.		[Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data
R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2** and **R3**.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Reactive Power generating capability per R1.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2 and R3**. The Transmission Owner has been added to include	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
	synchronous condensers that are under the control of the TO.	condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data

Project 2007-09 Generator Verification
MOD-025-1 DRAFT Mapping Document

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
1. Number: MOD-025-1	Proposed standard will cover MOD-025-1 content and will include requirements from MOD-024-1.	**1. Number:** MOD-025-2
2. Title: Verification of Generator Gross and Net Reactive Power Capability	Data Reporting has been added to reflect related requirements in the proposed Standard. Real has been added to include requirements from MOD-024-1.	**2. Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
3. Purpose: To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The Purpose has been modified to ensure that planning entities have accurate generator Real and Reactive Power capability data.	**3. Purpose:** To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
4. Applicability: **4.1.** Regional Reliability Organization. **4.2.** Generation Owner.	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined. Facility Applicability has been added.	**4. Applicability:** **4.1 Functional entities** 4.1.1 Generator Owner 4.1.2 Transmission Owner that owns synchronous condenser **4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.
R1. The Regional Reliability Organization	Regional applicability is	**Requirements R1, R2 and R3** defines the verification and data

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:	eliminated and functional entity responsibility is defined Verification, including reporting, is addressed throughout proposed Standard.	reporting previously addressed by regional procedures. These requirements are detailed in the following mapping.
R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	Exemption criteria are addressed by Section 4.2, **Applicability,** which follows the Registry Criteria.	**4.2 Facilities:** For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following: 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System. 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.2. Criteria for reporting generating unit auxiliary loads.	**R1** references **Attachment 1.** **Attachment 1**, Section 4 refers to Attachment 2, which is a reporting form or the basis for developing a more specialized form that provides all the auxiliary information required by the Standard. **Attachment 1,** section 4.1 allows engineering estimates in those situations where metering to measure a reactive load is not installed.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and ~~shall verify~~ (ii) the Reactive Power capability of its synchronous condenser ~~units in accordance with Attachment 1~~. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.
R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data,	**Requirements R2 and R3,** reference **Attachment 1.** Section 2 of **Attachment 1** prescribes the details of how the verification should be	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
commissioning data, performance tracking, and testing, etc.	performed.	~~shall verify~~ (ii) the Reactive Power capability of its synchronous condenser units ~~in accordance with Attachment 1~~. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
R1.4. Periodicity and schedule of model and data verification and reporting.	**Requirements R2 and R3,** reference **Attachment 1.** Section 5 of **Attachment 1** details the periodicity.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and ~~shall verify~~ (ii) the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data
R1.5. Information to be verified and reported: **R1.5.1.** Seasonal gross and net Reactive Power generating capabilities while at the Seasonal Real Power generating capability as reported in accordance with MOD-024-2. **R1.5.2.** Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc. **R1.5.3** Verified Reactive Power of	**Requirements R2 and R3,** reference **Attachment 1.** Section 3 of **Attachment 1** details the data to be recorded during the verification.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and ~~shall verify~~ (ii) the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data.

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
Auxiliary loads. **R1.5.4.** Method of verification, including date and conditions.		**R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data
R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined in **R2** and **R3**.	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and ~~shall verify~~ (ii) the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
approval.		containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data
R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its Reactive Power	Regional Reliability Organization applicability is eliminated and functional entity responsibility is defined	**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
generating capability per R1.	in **R2 and R3**. The Transmission Owner has been added to include synchronous condensers that are under the control of the TO.	**2.1.** Verify, units in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and ~~shall verify~~ (ii) the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for verification using historical operational data. **R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1.** Verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. **3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test or (ii) the date the data is selected for

MOD-025-1 Mapping to Proposed NERC Reliability Standard MOD-025-2		
Standard MOD-025-1 NERC Board Approved	**Comment**	**Proposed Standard MOD-025-2**
		verification using historical operational data

Standards Announcement

Project 2007-09 Generator Verification – MOD-025-2, MOD-026-1, MOD-027-1 and PRC-019-1

Recirculation Ballots are now open through 8 p.m. Friday, December 21, 2012

Now Available

A recirculation ballot window for each of the following four standards and the associated implementation plans is now open through **8 p.m. Eastern on Friday, December 21, 2012**:

- **MOD-025-2** – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability (please note that the implementation plan for this standard retires MOD-024-1 in addition to MOD-025-1),
- **MOD-026-1** – Verification of Models and Data for Generator Excitation Control Systems Functions and Plant Volt/Var Control Functions,
- **MOD-027-1** – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions, and
- **PRC-019-1** – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection.

After considering stakeholder comments from the formal comment period and successive ballot that ended on October 31, 2012, the drafting team made no substantive changes to the Requirements of the standards, but did make some clarifying changes as summarized in each of the Consideration of Comments posted on the project page.

The other standard in this project, PRC-024-1, has been posted for a 30-day comment period and successive ballot ending on January 11, 2013 and was sent in a separate announcement.

Instructions

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the recirculation ballot.

Members of the ballot pools associated with this project may log in and submit their vote for each of the standards by clicking here.

Next Steps

Voting results will be posted and announced after the ballot window closes. If approved, the standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

These standards were revised and posted for subsequent comment periods. The drafting team incorporated industry feedback to improve the standards and has posted them for a concurrent comment and ballot period.

Additional information is available on the project page.

NERC

Standards Process

The [Standard Processes Manual] contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 Generator Verification
MOD-025-2, MOD-026-1, MOD-027-1 and PRC-019-1

Recirculation Ballots Results

Now Available

A recirculation ballot for each of the following four standards and the associated implementation plans concluded at **8 p.m. Eastern on Friday, December 21, 2012**:

- **MOD-025-2** – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability (please note that the implementation plan for this standard retires MOD-024-1 in addition to MOD-025-1),
- **MOD-026-1** – Verification of Models and Data for Generator Excitation Control Systems Functions and Plant Volt/Var Control Functions,
- **MOD-027-1** – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions, and
- **PRC-019-1** – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection.

The other standard in this project, PRC-024-1, is currently posted for a 30-day comment period and successive ballot ending on January 11, 2013.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results.

Standard	Approval
MOD-025-2	Quorum: 86.89% Approval: 73.06%
MOD-026-1	Quorum: 79.00% Approval: 79.36%
MOD-027-1	Quorum: 86.68% Approval: 74.27%

PRC-019-1	Quorum: 85.87% Approval: 73.63%

Next Steps

The standards will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

The purpose of Project 2007-09 - Generator Verification - is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

These standards were revised and posted for subsequent comment periods. The drafting team incorporated industry feedback to improve the standards and has posted them for a concurrent comment and ballot period.

Additional information is available on the project page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2007-09 Recirculation Ballot MOD-025_in
Ballot Period:	12/12/2012 - 12/21/2012
Ballot Type:	Recirculation
Total # Votes:	318
Total Ballot Pool:	366
Quorum:	**86.89 % The Quorum has been reached**
Weighted Segment Vote:	73.06 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	44	0.647	24	0.353	14	8
2 - Segment 2.	9	0.5	5	0.5	0	0	3	1
3 - Segment 3.	82	1	35	0.583	25	0.417	11	11
4 - Segment 4.	27	1	12	0.706	5	0.294	4	6
5 - Segment 5.	91	1	37	0.587	26	0.413	12	16
6 - Segment 6.	50	1	28	0.718	11	0.282	7	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	5	0.5	0	0	1	1
9 - Segment 9.	3	0.3	3	0.3	0	0	0	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	0	1
Totals	**366**	**6.9**	**174**	**5.041**	**92**	**1.859**	**52**	**48**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	

1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Negative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		

3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	

4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	

5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Abstain	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	

6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Ballot Results	
Ballot Name:	Project 2007-09 Recirculation Ballot MOD-026_in
Ballot Period:	12/12/2012 - 12/21/2012
Ballot Type:	Recirculation
Total # Votes:	252
Total Ballot Pool:	319
Quorum:	**79.00 % The Quorum has been reached**
Weighted Segment Vote:	79.36 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	85	1	45	0.726	17	0.274	6	17
2 - Segment 2.	6	0.4	2	0.2	2	0.2	1	1
3 - Segment 3.	68	1	33	0.75	11	0.25	9	15
4 - Segment 4.	25	1	14	0.875	2	0.125	4	5
5 - Segment 5.	76	1	34	0.654	18	0.346	7	17
6 - Segment 6.	42	1	25	0.833	5	0.167	4	8
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	5	0.5	0	0	1	2
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.5	5	0.5	0	0	0	2
Totals	**319**	**6.6**	**165**	**5.238**	**55**	**1.362**	**32**	**67**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric	Dale Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Negative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor		
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff		
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		

1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Southwestern Power Administration	Gary W Cox		
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Negative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown		
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David Anderson		

3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton		
5	City of Tallahassee	Karen Webb	Negative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	

5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Cowlitz County PUD	Bob Essex	Negative	
5	CPS Energy	Robert Stevens	Negative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Abstain	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	

6	Constellation Energy Commodities Group	Brenda L Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton		
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Ballot Results	
Ballot Name:	Project 2007-09 Recirculation Ballot MOD-027_in
Ballot Period:	12/12/2012 - 12/21/2012
Ballot Type:	Recirculation
Total # Votes:	319
Total Ballot Pool:	368
Quorum:	**86.68 % The Quorum has been reached**
Weighted Segment Vote:	74.27 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	92	1	52	0.732	19	0.268	12	9
2 - Segment 2.	9	0.6	4	0.4	2	0.2	2	1
3 - Segment 3.	82	1	44	0.698	19	0.302	8	11
4 - Segment 4.	27	1	13	0.722	5	0.278	3	6
5 - Segment 5.	91	1	38	0.585	27	0.415	10	16
6 - Segment 6.	50	1	32	0.762	10	0.238	4	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	5	0.5	0	0	1	1
9 - Segment 9.	3	0.3	3	0.3	0	0	0	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	0	1
Totals	**368**	**7**	**196**	**5.199**	**83**	**1.801**	**40**	**49**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Negative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		

3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	LaGen	Richard Comeaux		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish	John D Martinsen	Affirmative	

	County			
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Negative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	

5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Abstain	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Ballot Results	
Ballot Name:	Project 2007-09 Recirculation Ballot PRC-019 December 2012_in
Ballot Period:	12/12/2012 - 12/21/2012
Ballot Type:	Recirculation
Total # Votes:	316
Total Ballot Pool:	368
Quorum:	**85.87 % The Quorum has been reached**
Weighted Segment Vote:	73.63 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	94	1	46	0.648	25	0.352	12	11
2 - Segment 2.	9	0.6	6	0.6	0	0	2	1
3 - Segment 3.	83	1	39	0.6	26	0.4	6	12
4 - Segment 4.	25	1	13	0.684	6	0.316	2	4
5 - Segment 5.	90	1	37	0.597	25	0.403	11	17
6 - Segment 6.	50	1	29	0.725	11	0.275	5	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	5	0.5	0	0	1	1
9 - Segment 9.	3	0.3	3	0.3	0	0	0	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	0	1
Totals	**368**	**7**	**183**	**5.154**	**94**	**1.846**	**39**	**52**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Abstain	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Theresa Allard	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	

1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Negative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		

3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Norman D Harryhill		
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Negative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	First Solar, Inc.	Robert Jenkins		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	ICF International	Brent B Hebert	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern California Power Agency	Hari Modi		
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	

5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Abstain	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Claire Lloyd	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Negative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tenaska Power Services Co.	John D Varnell	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Brendan Kirby	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Affirmative	
10	Midwest Reliability Organization	James D Burley		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

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Account Log-In/Register

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 of PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from February 29 – March 29, 2012.
8. Draft 4 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from September 28 – October 31, 2012.
9. Draft 5 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from December 12, 2012 – January 11, 2013.

Proposed Action Plan and Description of Current Draft:

This is the sixth draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This sixth posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop sixth version draft standard.	January 2013
2. Post response to comments and conduct successive ballot.	February 2013
3. Develop responses to ballot comments.	March 2013

4. Post responses to comments and conduct recirculation ballot.	April 2013
5. BOT adoption.	May 2013
6. File with regulatory authorities.	June 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.2. In those jurisdictions where regulatory approval is not required:

   5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection[2]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[3] that prevents an applicable generating unit from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time

[3] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

M4. Each Generator Owner shall have evidence that it communicated generator protective relay settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4, Measures M1 through M4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit has no documented and communicated regulatory or equipment limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit has no documented and communicated regulatory or equipment limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

Version History

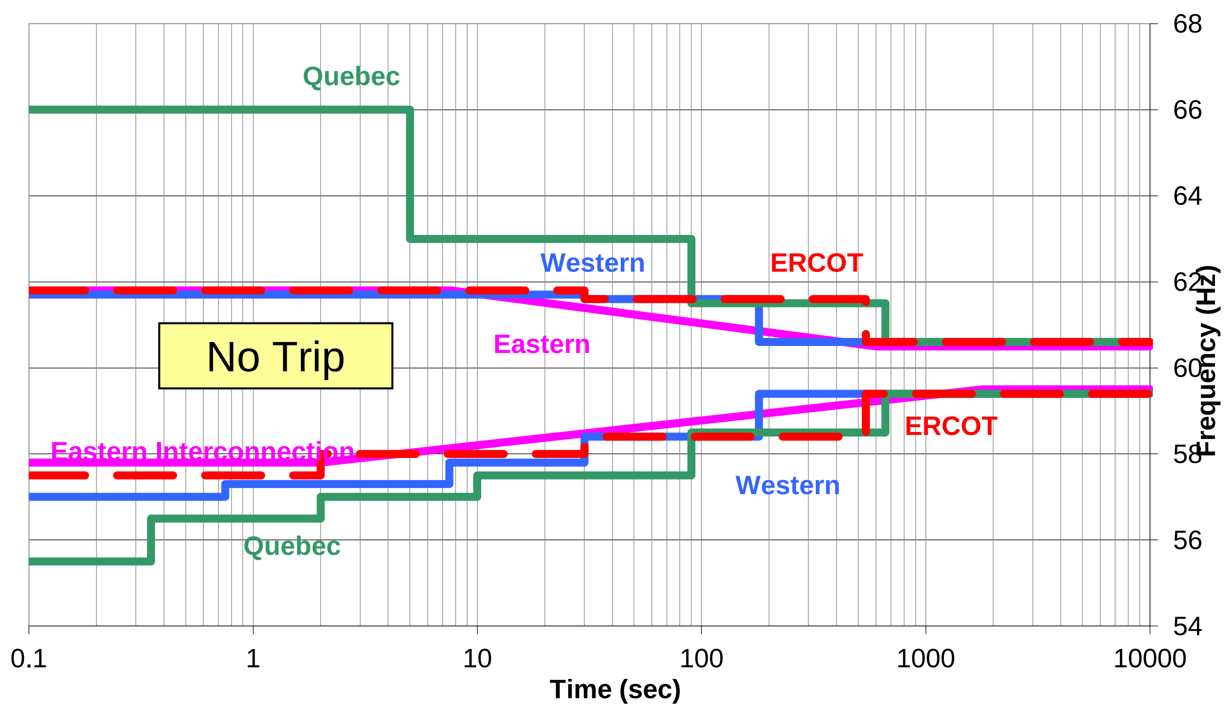
Version	Date	Action	Change Tracking

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

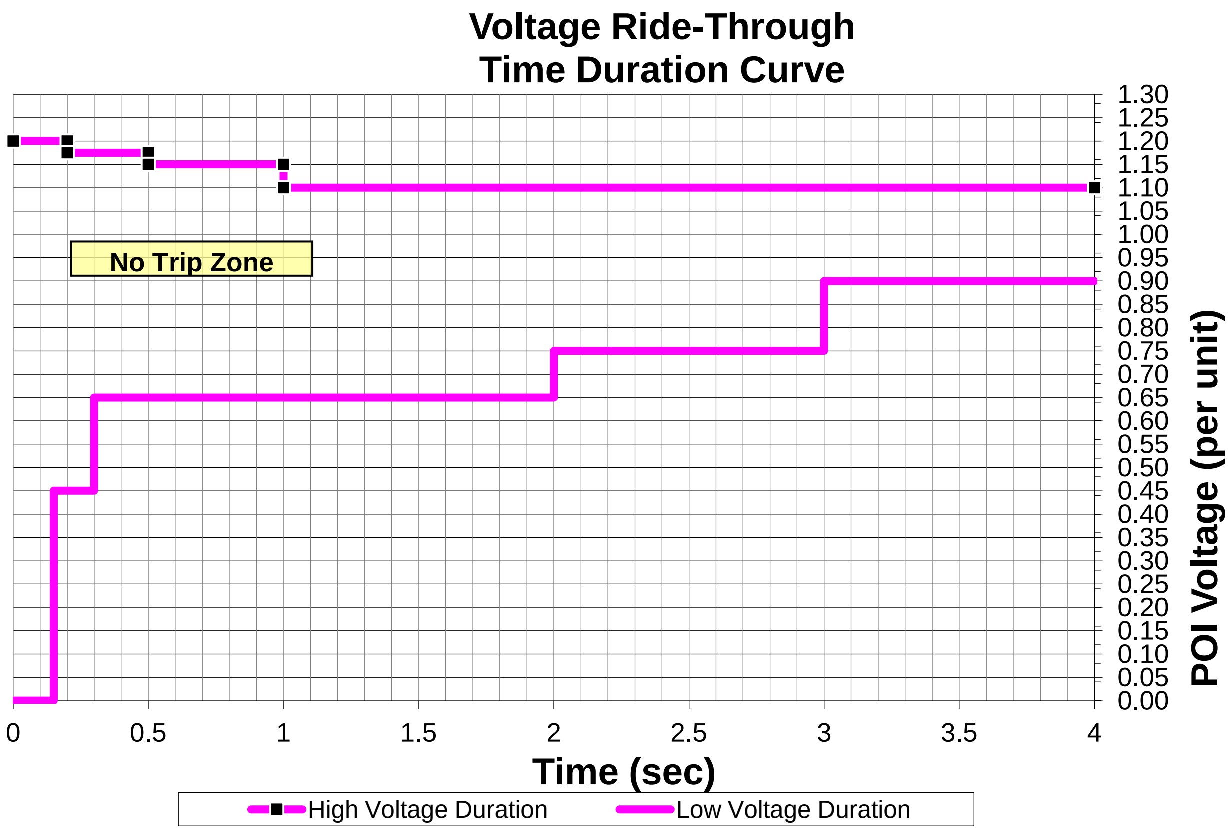
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 of PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from February 29 – March 29, 2012.
8. Draft 4 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from September 28 – October 31, 2012.
9. ~~8.~~ Draft 5 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from December 12, 2012 – January 11, 2013.

Proposed Action Plan and Description of Current Draft:

This is the sixth~~fifth~~ draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This sixth~~fifth~~ posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop sixth ~~fifth~~ version draft standard.	~~December 2012~~ January 2013
2. Post response to comments and conduct successive ballot.	February ~~December~~ 2013~~2~~

3. Develop responses to ballot comments.	March~~January~~ 2013
4. Post responses to comments and conduct recirculation ballot.	April~~January~~ 2013
5. BOT adoption.	May~~February~~ 2013
6. File with regulatory authorities.	June~~March~~ 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings ~~Performance During Frequency and Voltage Excursions~~

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. ~~and ensure expected generating unit performance during frequency and voltage excursions is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.~~

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

   5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

   5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

   5.2. In those jurisdictions where regulatory approval is not required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set ~~such~~ its protective relaying such~~o~~ that the frequency protective relaying does not ~~operate to~~ trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a)~~the~~ generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection[2]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set~~or~~ its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. ~~if the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2~~ Requirement R2 is subject to the following exceptions~~-~~: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[3] that prevents an applicable generating unit from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice~~sory~~. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~.~~

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator~~ and Transmission Planner within 30 calendar days of any of the following:

- Identification of a~~n~~ regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- ~~Modification or upgrade of the equipment causing the limitation that results in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).~~

~~**R4.** Within 60 calendar days of receipt of a written request from a Planning Coordinator or Transmission Planner, each Generator Owner shall provide an estimate of the time duration which the generating unit(s) will remain connected (including the performance of the auxiliary systems) if the unit(s) were to experience a frequency or voltage excursion. The voltage or frequency profile at the point of interconnection is provided by a Planning Coordinator or Transmission Planner that models the associated generating unit(s) and which has requested the time duration estimate.~~

[3] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

~~If the Generator Owner expects the generating unit(s) will remain connected for the duration of the profile of the excursion provided, the estimate should indicate the generating unit(s) is not expected to trip. The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment. Detailed generating unit(s) performance studies are not required to develop the estimate. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~

~~R5.~~R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner ~~(~~that models the associated unit~~),~~ within 60 calendar days of receipt of a written request for the data~~,~~ and within 60 calendar days of any change to those previously requested trip settings unless ~~otherwise~~ directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets~~,~~ or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 ~~evidence~~ such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, ~~or~~ dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3~~that are caused by generator frequency and voltage protective relays~~) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.

~~**M4.** Each Generator Owner shall have evidence that an estimate of the time duration of its existing generating unit(s) as a result of a frequency excursion or voltage excursion has been communicated in accordance with Requirement R4, such as a copy of the estimate of time duration report and correspondence, such as dated e-mails, or other documentation and copies of any requests it has received for that information.~~

~~M5.~~M4. Each Generator Owner shall have evidence that it communicated generator protective relay settings ~~to a requesting entity within 60 calendar days of a request or change in setting(s)~~ in accordance with Requirement R4~~5~~, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.~~.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4~~5~~, Measures M1 through M4~~5~~; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit has no documented and communicated regulatory or equipment limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit has no documented and communicated regulatory or equipment limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator~~ and Transmission Planner more than 30 calendar days but less than or equal to ~~40~~ 60 calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator~~ and Transmission Planner more than 6~~4~~0 calendar days but less than or equal to 9~~5~~0 calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator~~ and Transmission Planner more than 9~~5~~0 calendar days but less than or equal to 12~~6~~0 calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its ~~Reliability Coordinator,~~ Planning Coordinator~~, Transmission Operator~~ and Transmission Planner within 12~~6~~0 calendar days of identifying the limitation.
~~R4~~	~~The Generator Owner provided an estimate of a unit's performance more than 60 calendar days but less than or equal to 70 calendar days of a written request.~~	~~The Generator Owner provided an estimate of a unit's performance more than 70 calendar days but less than or equal to 80 calendar days of a written request.~~	~~The Generator Owner provided an estimate of a unit's performance more than 80 calendar days but less than or equal to 90 calendar days of a written request.~~	~~The Generator Owner failed to provide an estimate of a unit's performance within 90 calendar days of a written request.~~ ~~.~~
R4~~5~~	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to ~~7~~90 calendar days of any change to those trip settings.	The Generator Owner provided its generator protection trip settings more than 9~~7~~0 calendar days but less than or equal to 120~~80~~ calendar days of any change to those trip settings.	The Generator Owner provided its generator protection trip settings more than 12~~8~~0 calendar days but less than or equal to 150~~90~~ calendar days of any change to those trip settings.	The Generator Owner failed to provide its generator protection trip settings within 150~~90~~ calendar days of any change to those trip settings.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 9~~7~~0 calendar days of a written request.	OR The Generator Owner provided trip settings more than 9~~7~~0 calendar days but less than or equal to 12~~8~~0 calendar days of a written request.	OR The Generator Owner provided trip settings more than 12~~8~~0 calendar days but less than or equal to 15~~9~~0 calendar days of a written request.	OR The Generator Owner failed to provide trip settings within 15~~9~~0 calendar days of a written request for the data.

E. Regional Variances

None

F. Associated Documents

None

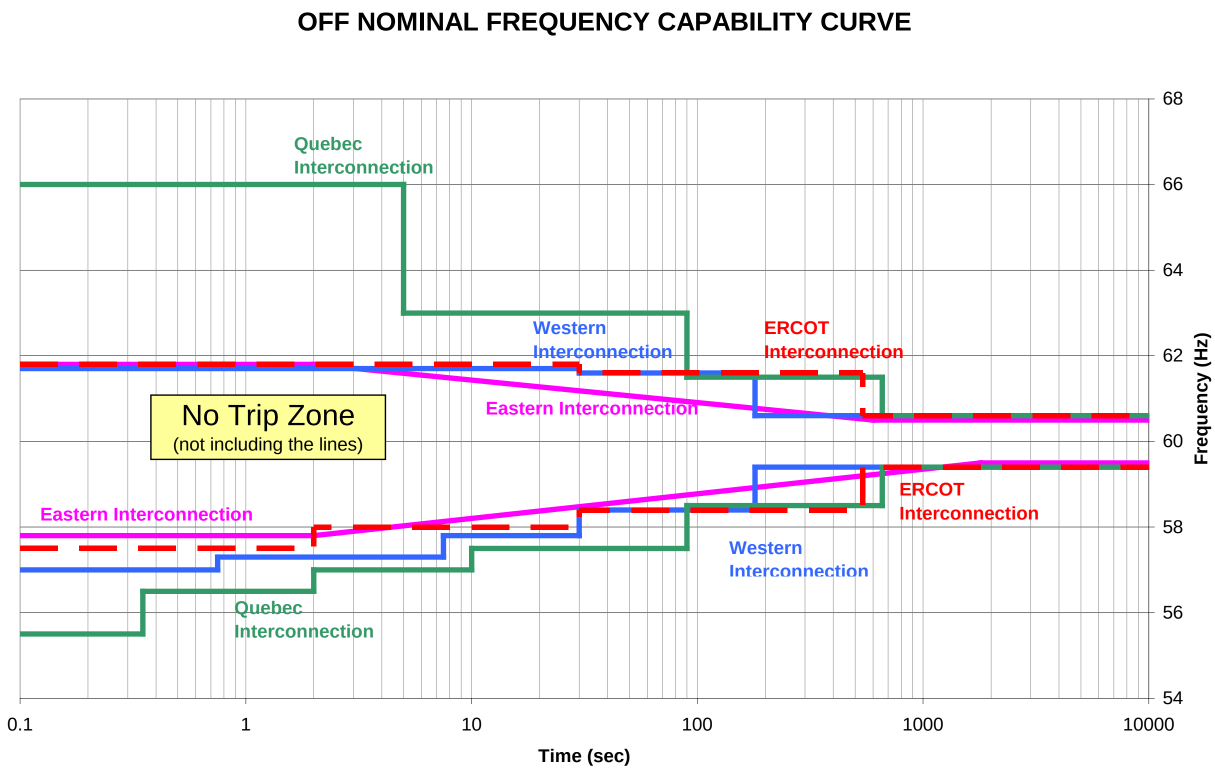
Version History

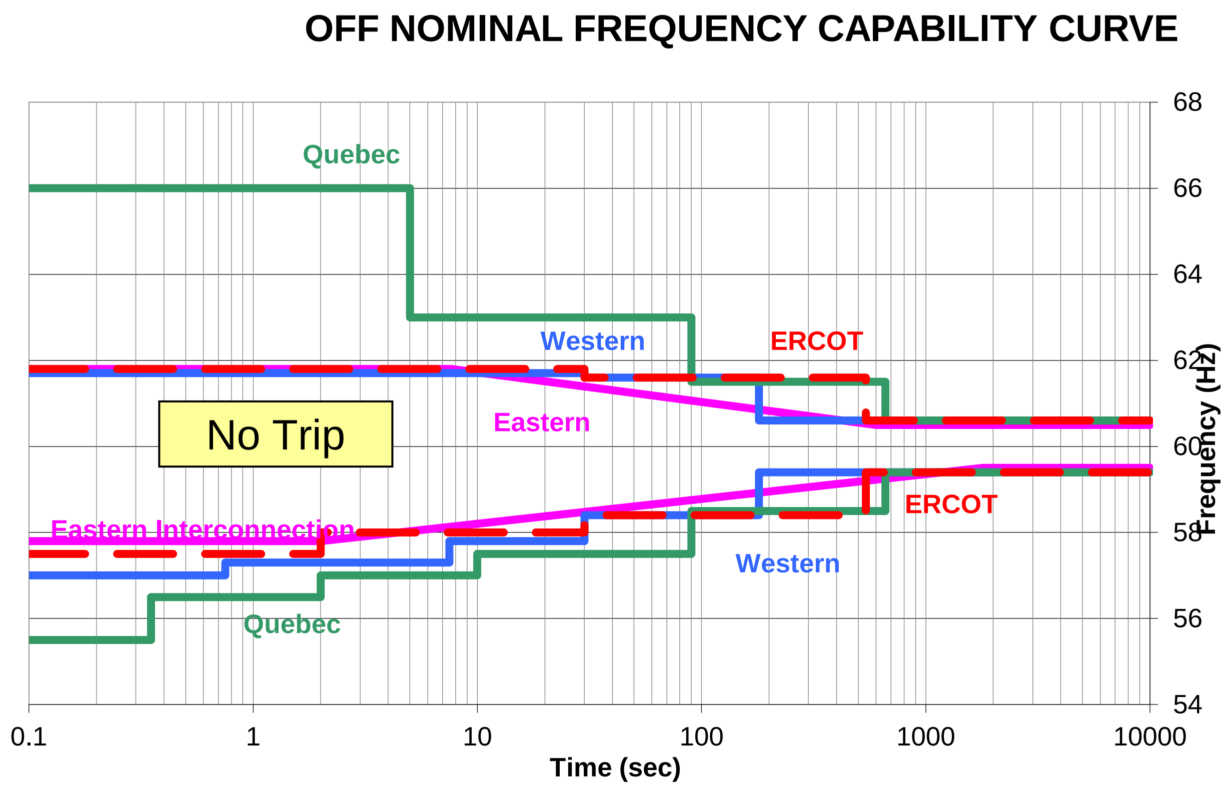
Version	Date	Action	Change Tracking

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1





Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	10^(90.935~~118.0602~~-1.45713~~9055~~*f)	≤59.5	10^(1.7373*f-100.116)
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

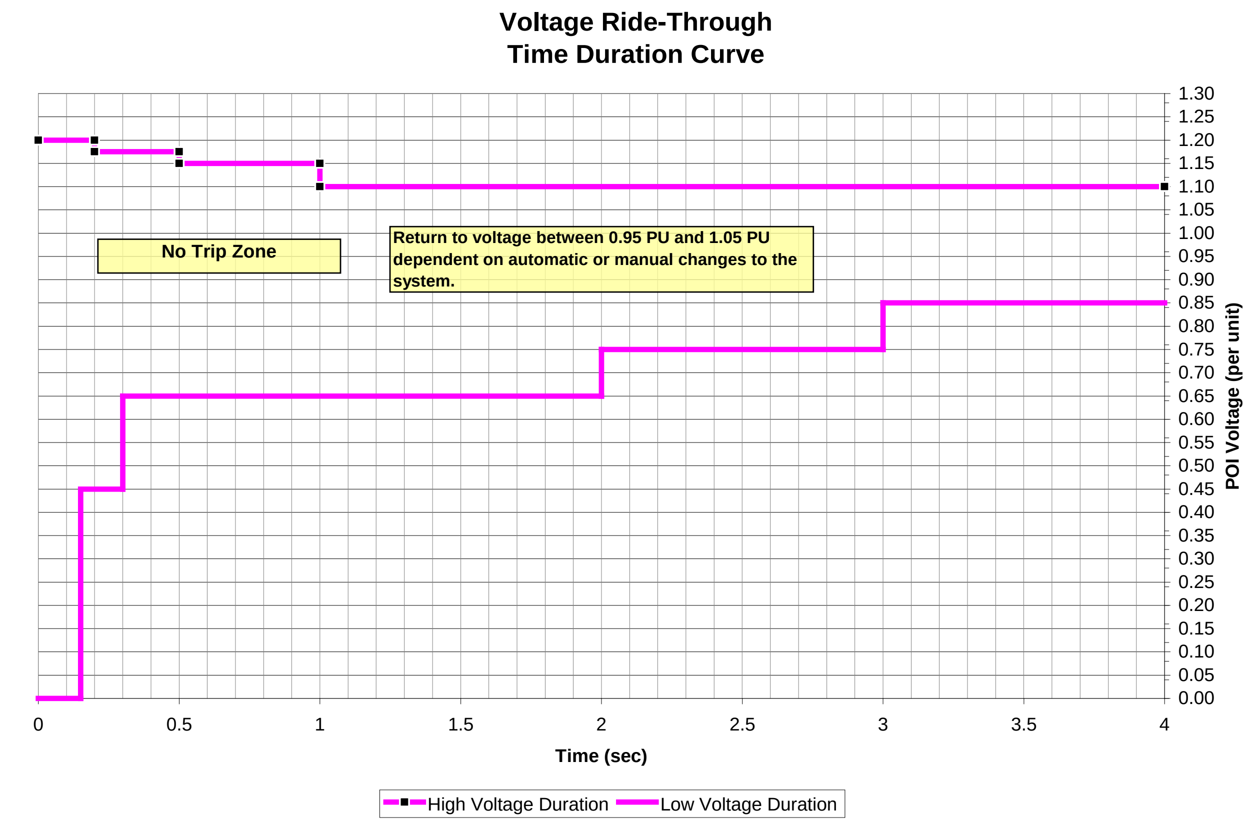
Quebec Interconnection

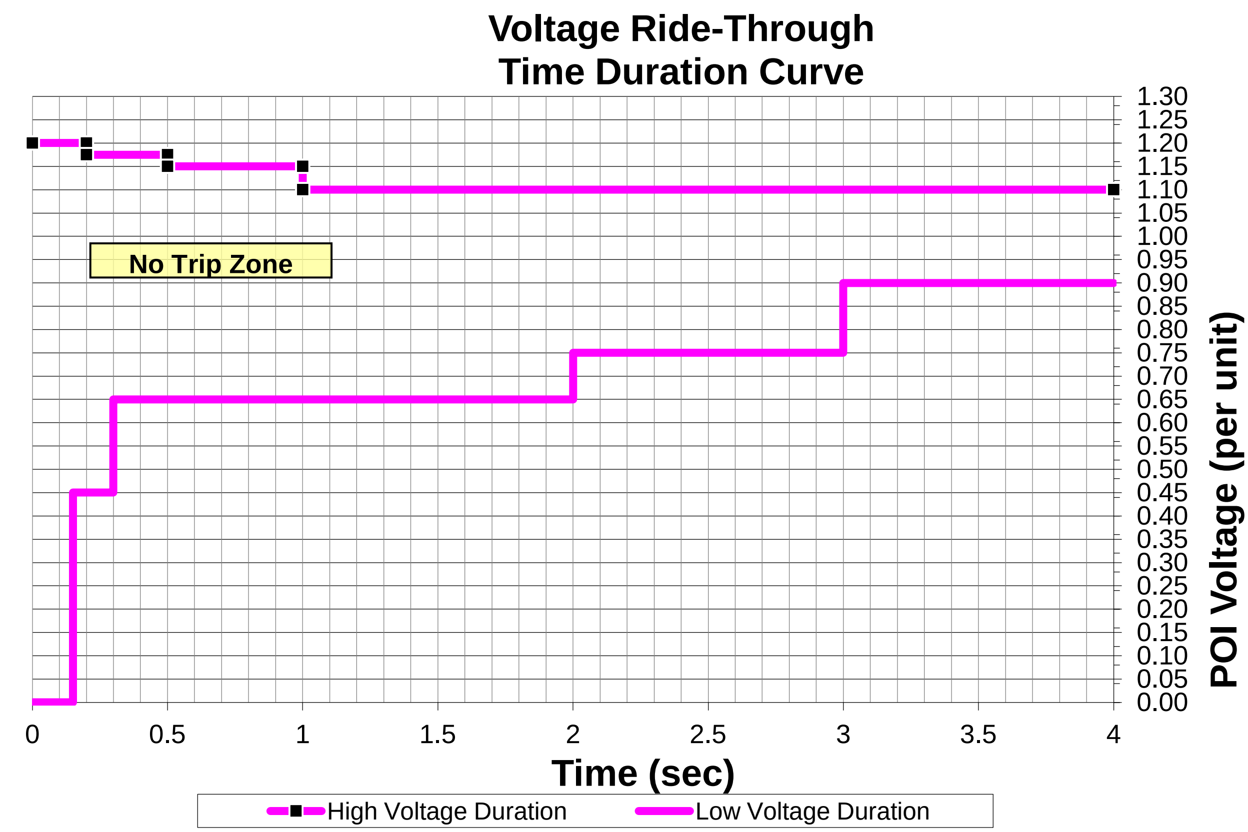
High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024~~—~~ Attachment 2





Ride Through Duration~~Curve Data Points~~:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	~~0.00~~≤0.45	0.15
≥1.175	0.20	~~≤0.45~~≤0.65	0.30
≥1.15	0.50	~~≤0.65~~≤0.75	2.00
≥1.10	1.00	~~≤0.75~~≤0.90	3.00
~~>1.05~~	~~600~~	~~<0.90~~	~~600~~
~~≤1.05~~	~~Continuous operation~~	~~≥0.95~~	~~Continuous operation~~

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may ~~A~~adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz. ~~normal.~~
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.~~,~~
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals~~)~~.
   ~~c.~~d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Frequency and Voltage Protective Relay Settings

Approvals Required

PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024-1 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to

such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, and R4 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Frequency and Voltage Protective Relay Settings ~~Performance During Frequency and Voltage Excursions~~

Approvals Required

PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings~~Performance During Frequency and Voltage Excursions~~.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024-1 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.
- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4~~, and R5~~.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, and R4~~, and R5~~ involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Unoffical Comment Form

Project 2007-09 Generator Verification PRC-024-1 Generator Frequency and Voltage Protective Relay Settings

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed revisions to PRC-024-1. Comments must be submitted by by 8 p.m. ET **Monday, February 25, 2013**. If you have questions please contact Stephen Crutchfield at stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The Generator Verification Standard Drafting Team posted PRC-024-1 - Generator Frequency and Voltage Protective Relay Settings, from December 12, 2012 through January 11, 2013 for a 30-day concurrent comment/successive ballot period. The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

The vast majority of stakeholders agreed with the removal of R5 from the standard. Several stakeholders suggested that there were issues with R4. These commenters pointed out that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as "sound engineering judgment" is subject to interpretation and vague. Based on these comments, the GVSDT removed R4 from the standard. PRC-024-1 is now a relay setting standard.

Minority issue: Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard. The proposed draft of PRC-024 does not accomplish this. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection Agreements and not NERC Standards.

A large majority of stakeholders agreed with the change made to Attachment 1. Some stakeholders questioned the potential impact this change might make due to the elimination of the margin between the allowable UFLS overshoot and the generator overfrequency trip setpoints. The GVSDT pointed out that setting overfrequency tripping at this point would be allowed under the previous curve as a technically-based exemption under Requirement R3 and the change made removes a conflict with internationally-recognized technical standards.

Most stakeholders agreed with the revisions to the voltage ride-through curves in Attachment 2. Several stakeholders had concerns with the low voltage ride-through criteria being lowered to 85% for the 3-4 second interval. Stakeholders pointed out that transmission systems are designed to operate between 90% to 110% and not down to 85% and as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. The GVSDT agrees with these comments and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The majority of commentators agreed with the removal of loadability relays from PRC-024. The majority of comments expressed agreement with the removal of loadability relays from PRC-024. One commentator recommended that the Generator Relay Loadability drafting team vet the removal of these relay types from Footnote 1. The GVSDT had previous discussions with that drafting team and they concurred with the revision to PRC-024.

Stakeholders provided valuable input regarding suggested improvements to language within the standard. Based on these comments, the following improvements were made to the draft standard:

- Removed R4 from the standards because of ambiguous language and dubious reliability benefit.
- Revised the title of the standard to “Generator Frequency and Voltage Protective Relay Settings” and the Purpose Statement to “Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
- Revised “generating unit(s)” to “applicable generating unit(s)” to reflect that the standard only applies to units that meet the registry criteria.
- Revised language of R1 to match that of R2.
- Added “regulatory or” language regarding limitations to reflect that NERC, environmental or regulatory requirements may cause a limitation in generator performance.
- Revised R2 so that the sentences were shorter and easier to read.
- Removed the last bullet from R3 and added and new bullet referencing frequency impacts on turbines as follows: “Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.”
- Revised R5 (now R4) to indicate that the trip settings to be provided are only those “associated with Requirements R1 and R2” and not all relays.
- Revised the measures based on requirement revisions.
- Updated the VSLs for R3 and R4 to allow 30 day increments between levels rather than the original 10 days. This comports with other standards developed under this project.
- Updated the table in Attachment 2 (this was missed in the previous revision).

- Made clarifying revisions to “Voltage Ride-Through Curve Clarifications” on the last page of the standard.
- Clarified Footnote 3 to: “Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.”

Questions

1. The GVSDT has removed Requirement R4 from the standard. Stakeholders suggested that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as “sound engineering judgment” is subject to interpretation and vague. Do you agree with this revision? If not, please explain in the comment area below.

   ☐ Yes

   ☐ No

   Comments:

2. Do you have any other comment, not expressed in question above, for the GVSDT?

   Comments:

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024-1		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 states "… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R2 and the voltage ride through curves in PRC-024 Attachment 2 accomplish this. While the curves were developed based on three phase normally cleared faults located at a generating plant substation (the most severe condition for generating equipment), the curves cover voltages depressed as low as 0.65 per unit for two seconds, which the GVSDT feels will cover the Category B and C events of concern to the Commission. Requirement R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented regulatory or technical reasons, but directs those generators to communicate that limitation to the PC and TP so its performance can be modeled correctly.
Paragraph 1787 also states "… the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented regulatory limitations. The GVSDT

Project 2007-09 Generator Verification — PRC-024-1		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		believes that NRC requirements qualify as regulatory limitations for the purposes of this standard.

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024-1		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 states "… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R2 and the voltage ride through curves in PRC-024 Attachment 2 accomplish this. While the curves were developed based on three phase normally cleared faults located at a generating plant substation (the most severe condition for generating equipment), the curves cover voltages depressed as low as 0.65 per unit for two seconds, which the GVSDT feels will cover the Category B and C events of concern to the Commission. Requirement R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented regulatory or technical reasons, but directs those generators to communicate that limitation to the PC and TP so its performance can be modeled correctly. ~~In addition, Requirement R4 allows the PC or TP to request an estimate of performance (ride through duration) from the GO for a defined excursion. The estimate would cover process upsets to the generating equipment that might result in a delayed trip, even if the generator protection itself did not cause a trip.~~

Project 2007-09 Generator Verification — PRC-024-1		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 also states "… the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented regulatory ~~technical~~ limitations. The GVSDT believes that NRC requirements qualify as regulatory ~~technical~~ limitations for the purposes of this standard.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:
There are four requirements in PRC-024-1. Two of the Requirements (R1 and R2) were assigned a "Medium" VRF and the remaining two requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The "Lower" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The “Lower” VRF assigned is based on the reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings~~Generator Performance During Frequency and Voltage Excursions~~.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:

There are four ~~five~~ requirements in PRC-024-1. Two of the Requirements (R1~~,~~ and R2) were assigned a "Medium" VRF and the remaining two~~hree~~ requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2~~ and R5, both of~~ which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. ~~.~~ Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 ~~and R5, both of~~ which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The "Lower" VRF assigned is based on the reliability objective specified.

~~**VRF for PRC-024-1, Requirement R4:**~~

- ~~FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 contains Parts that are procedural in nature defining criteria associated with the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.~~
- ~~FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires an estimate of performance and is somewhat similar in concept with both PRC-009-0 Requirement R1 and PRC-014-0 Requirement R2, both of which reference protection analysis or assessment for determining adequacy. In addition, as is generally the case with reliability standard VRF definitions for analysis & assessment planning type requirements, this requirement is assigned a "Lower" VRF.~~
- ~~FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to estimate performance during a frequency or voltage excursion is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the~~

~~emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.~~

- ~~FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to estimate performance during a frequency or voltage excursion. Requirement Parts and obligations are lower risk procedure based criteria for the main requirement. The "Lower" VRF assigned is based on the reliability objective specified.~~

VRF for PRC-024-1, Requirement R4~~5~~:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4~~5~~ does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4~~5~~ reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The "Lower" VRF assigned is based on the reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

~~***VSLs for PRC-024-1 Requirement R4:***~~

~~R#~~	~~Compliance with NERC VSL Guidelines~~	~~Guideline 1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~Guideline 2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~Guideline 3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~Guideline 4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~
~~R4.~~	~~The NERC VSL guidelines are satisfied by incorporating increments for tardiness.~~	~~This is a new Requirement and does not have a prior level of compliance.~~	~~Proposed VSL's reflect increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.~~	~~Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner per the procedure criteria specified by listed parts. Proposed VSL's are consistent with the requirement.~~	~~Proposed VSL's are based on a single violation and not a cumulative violation methodology.~~

VSLs for PRC-024-1 Requirement R~~4~~5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4~~6~~.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Standards Announcement

Project 2007-09 Generator Verification
PRC-024-1

Successive Ballot and Non-Binding Poll is now open through February 25, 2013

Now Available

A successive ballot of **PRC-024-1** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is now open **through 8 p.m. Eastern on Monday, February 25, 2013.**

Instructions
Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background
The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 Generator Verification
PRC-024-1

Formal Comment Period: January 25, 2013 – February 25, 2013

Upcoming:
Successive Ballot and Non-Binding Poll: February 15, 2013 – February 25, 2013

Now Available

A 30-day formal comment period is open for **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions through **8 p.m. Eastern on Monday, February 25, 2013**.

A successive ballot of **PRC-024-1** and non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Friday, February 15, 2013 through 8 p.m. Eastern on Monday, February 25, 2013.**

The remaining four standards (MOD-025-2, MOD-026-1, MOD-027-1 and PRC-019-1) in this project passed the recirculation ballot on December 21, 2012 and will be presented to the NERC Board of Trustees for adoption at its February meeting.

Instructions for Commenting

A formal comment period for **PRC-024-1** is open through **8 p.m. Eastern on Monday, February 25, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

A successive ballot of PRC-024-1 and non-binding poll of the associated VRFs and VSLs will be conducted from February 15, 2013 through February 25, 2013.

Background

The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

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- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Additional information is available on the project page.

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NERC
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RELIABILITY CORPORATION

Standards Announcement

Project 2007-09 Generator Verification
PRC-024-1

Successive Ballot and Non-Binding Poll Results

Now Available

A successive ballot of **PRC-024-1** and non-binding poll of the associated VRFs and VSLs concluded **at 8 p.m. Eastern on Thursday, February 28, 2013.**

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the successive ballot.

Approval	Non-binding Poll Results
Quorum: 78.80% Approval: 89.01%	Quorum: 76.38% Supportive Opinions: 84.24%

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background
The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

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- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
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- MOD-027-1 — Verification of Generator Unit Frequency Response

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Ballot Results	
Ballot Name:	Project 2007-09 PRC-024-1 Successive Ballot
Ballot Period:	2/15/2013 - 2/28/2013
Ballot Type:	Successive
Total # Votes:	249
Total Ballot Pool:	316
Quorum:	**78.80 % The Quorum has been reached**
Weighted Segment Vote:	89.01 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	82	1	49	0.845	9	0.155	8	16
2 - Segment 2.	6	0.4	4	0.4	0	0	1	1
3 - Segment 3.	68	1	44	0.88	6	0.12	4	14
4 - Segment 4.	25	1	14	0.875	2	0.125	3	6
5 - Segment 5.	76	1	45	0.882	6	0.118	7	18
6 - Segment 6.	42	1	27	0.871	4	0.129	1	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	5	0.5	1	0.1	0	2
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.6	6	0.6	0	0	1	0
Totals	**316**	**6.8**	**196**	**6.053**	**28**	**0.747**	**25**	**67**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	paul B johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden	Abstain	
1	Central Maine Power Company	Kevin L Howes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg		
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis		
1	Orlando Utilities Commission	Brad Chase		
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones		
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	

3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	

5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs		
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda L Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		

6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen		
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8		Edward C Stein		
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-binding Poll
Project 2007-09 PRC-024-1

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-09 Non-binding Poll PRC-024-1
Poll Period:	2/15/2013 - 2/28/2013
Total # Opinions:	236
Total Ballot Pool:	309
Summary Results:	76.38% of those who registered to participate provided an opinion or an abstention; 84.24%of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	paul B johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden	Abstain	
1	Central Maine Power Company	Kevin L Howes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		

1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg		
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis		
1	Orlando Utilities Commission	Brad Chase		
1	PacifiCorp	Colt Norrish	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones		
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
2	Alberta Electric System Operator	Mark B Thompson		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	Southwest Power Pool	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		

3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris		
3	Ocala Electric Utility	David Anderson	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	

4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		

5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	

6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	Exelon Power Team	Pulin Shah		
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	William T Moojen		
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	

10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (28 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
Question 1 (25 Responses)
Question 1 Comments (28 Responses)
Question 2 (0 Responses)
Question 2 Comments (28 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Individual
Thad Ness
American Electric Power
Yes
AEP recommends that the time allowed to meet R 3.1 be extended to 60 calendar days, aligning it with R4, thereby making the timing requirements of the standard more consistent throughout. R2: Regarding the language “If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying”, we believe the intent is to allow the GO to set its protective relaying within the PRC-024 no-trip zone and remain compliant so long as the Transmission Planner’s less stringent requirements is met. However it is not made explicitly clear by doing so that one would still be fully compliant with PRC-024. We recommend making this explicitly clear within R2. Suggest rewording the first sentence of R2 to state the following: “Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) that remains within the “no trip zone” of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant.”
Individual
Nazra Gladu
Manitoba Hydro
Yes
(1) R2 – are the words ‘the applicable generating units’ missing after the word ‘trip’ in the third

line? this would make the language consistent with the wording of R1. (2) R2- are the words ‘of a location specific Transmission Planner’s study’ precise enough to know for certain what characteristics are being referred to and compliance measured? (3) R3 – is the word ‘known’ precise enough to know for certain what characteristics are being referred to and compliance measured? (4) R3, 3.1 – there is no notification requirement with respect to any modifications or upgrades that may remove the limitation – this seems to be a gap. (5) M3 – the word ‘documentation’ should be changed to ‘information’. (6) M4 – does not seem to track the wording of R4 – measure should be that it ‘provided applicable generator protection trip settings’…….and the word ‘information’ should be ‘data’. (7) Compliance – same comment as previous re: use of the acronym CEA. (8) VSLs, R1 and R2 – the way these requirements are worded it makes it seem as though the violation is that the GO has no documented limitation – that is not the violation, that would be a violation of R3. The violation for these two requirements would be a failure to set its relaying within the criteria of R1/R2. (9) VSLs, R2 – doesn’t contemplate new change to language of R2 re: TP standards. (10) VSLs, R3 – the timeline doesn’t address any change other than the identification of the limitation, i.e. but the timeline could run from repair, replacement. (11) VSLs, R4 – some refer to a ‘written request’ and some refer to a ‘written request for the data’ – these should be made consistent with the requirement language.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Group
PacifiCorp
Ryan Millard
Yes
Individual
Daniela Hammons
CenterPoint Energy
CenterPoint Energy remains concerned with truncating the Voltage Ride-Through Time Duration Curve (Attachment 2) at 4 seconds due to coordination with undervoltage load shedding systems (UVLS). For coordination of UVLS with any generator voltage protective relays, CenterPoint Energy recommends the curve be extended to at least 10 seconds at 0.90 per unit POI Voltage. CenterPoint Energy does not believe such a change would be controversial, as the GVSDT states in the Consideration of Comments (Draft 5) that “Stakeholders pointed out that transmission systems are designed to operate between 90% to

110%.”
Group
Detroit Edison
Kent Kujala
Yes
Regarding Footnote 1 for R1, are protective functions within control systems that measure frequency from a non-electrical input such as speed sensors, included as "protective relaying"? Please clarify that this standard pertains only to generator protective functions that respond exclusively to voltage and/or frequency, but not current. Please adjust Attachment 1 Eastern Interconnection frequency data point exponents on page 13 so that they are completely visible. Please verify for Attachment 2 Voltage Curve that continuous operation is expected greater than 0.90 pu. and less than 1.10 pu.
Individual
Bill Fowler
City of Tallahassee
Yes
No
Group
Duke Energy
Greg Rowland
Yes
No
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No
R4 as it was rewritten in draft 6 seems like a redundant sub requirement of PRC-001 R3. The type of protection described in R2 and R3 falls already in the “coordination” required category described in the NERC Technical Reference Document, “Power Plant and Transmission System Protection Coordination” Revision 1 – July 2010 http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf Furthermore the requirement fails to specify the accountability and responsibilities of the Transmission Planner/Transmission Operator in the “coordination” process in order to approve the relay setting changes. R4 should be eliminated or merged into PRC-001 R3 to avoid redundancies per FERC’s instructions on eliminating redundancies.
PRC-024-1 previous draft placed the burden of complying with the standard solely on the GO.

This new draft places the bulk of ensuring compliance on the GO while providing a different criteria or “exemption” given by the Transmission Planner. If that is the case, the Planner should have a joint obligation to ensure the GO/GOP is successful in meeting and achieving compliance spelled out in the standard. Additionally, the Planner would be the best party capable of determining “which voltage protective relaying setting does not trip as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. Applicability of the standard should also include the Transmission Planner. R2 also lacks a mechanism(how the study is initiated and why, study request timeframe, study response timeframe, etc) whereby the Transmission Planner provides the “less stringent” voltage protection requirements so the GO can then determine when they need to follow Attachment 2 or the Planner’s study or have the Planner determine the criteria first. The requirement should be clearer and more details should be added. R3 objectives state that the GO shall provide equipment limitations to the Planner within 30 days of a request or change. PRC-024-1 R3 does not provide any value when MOD-010, MOD-012 and MOD-025, MOD-026 and MOD-027 appear to address these issues. R3 needs to be clarified with more details to avoid possible redundancies with the MOD standards.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Group
Southern Company - Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Yes
Individual
John Seelke
Public Service Enterprise Group
Yes
Yes. For generators without frequency or voltage protective relaying, R1 and R2 respectively do not require these relays to be installed per footnote 1. However, R3 could be interpreted to require generators without such relaying to be required to comply with R3 because it applies to a generator limitation that “prevents an applicable generating unit from meeting the relay

setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice." We have received an e-mail from the drafting team NERC coordinator for this project that this is NOT the intent of R3 – R3 is only intended to apply to generators that HAVE frequency and/or voltage protective relaying installed. We ask that the SDT confirm this understanding. If this is the SDT's intent we recommend that R3 be clarified as follows: Each Generator Owner shall document each known regulatory or equipment limitation3 that prevents an applicable generating unit WITH GENERATOR FREQUENCY OR VOLTAGE PROTECTIVE RELAYS from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. Alternative wording to clarify R3's intent that it does not apply to generators witout frequency or voltage protective relaying would be acceptable.
Group
Luminant
Brenda Hampton
Yes
Individual
Chang G. Choi
City of Tacoma, Tacoma Public Utilities, Tacoma Power
Yes
It is not completely clear how to implement Requirement R2 given the information contained in Attachment 2. Specifically, clarification is requested on the following two issues. A. In Attachment 2, what issue is Curve Detail 3 intended to address? Is it suggesting that definite-time voltage elements should be used, instead of inverse time elements, unless detailed analysis is performed? It is not clear if Curve Detail 3 is intended to afford entities additional flexibility or to require them to conduct more detailed analysis. B. In Attachment 2, is the section titled "Evaluating Protective Relay Settings" intended to determine the per unit voltage base, at the generator terminals, for the Voltage Ride-Through Time Duration Curve? Under Measurement M3, change "manufacturer's advisory" to "manufacturer's advice" to be consistent with Requirement R3. In Attachments 1 and 2, do the "no trip zones" include the lines? In other words, for the Western Interconnection, if a frequency element was set to 57.2 Hz, would an operating time of 0.75 seconds be acceptable per the standard, or does the operating time have to be above 0.75 seconds? (A similar question could be asked for the Voltage Ride-Through Time Duration Curve.) In Attachment 2, under "Evaluating Protective Relay Settings," change "use either the following…" to "use either of the following…"
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes

FOR: Requirement R1, REPLACE: "the frequency protective relaying" WITH: "that generator frequency protective relaying" RATIONALE: SDT intent, with the subordinate bulleted exceptions, appears to provide for exception of necessary overriding conditions within the "no trip zone" for which the "generator frequency protective relaying" is permitted to necessarily go ahead an trip the unit. This suggested change is an attempt to strengthen the linkage between the qualifying R1 "has generator frequency protective relaying activated...", and those bulleted exceptions in order to calm industry concern that those bullets form the only permissible set of unit protective relaying conditions that are allowed to trip the trip (protect) the unit and its underlying equipment when operating within the units' "no trip zone" of frequency conditions. FOR: Requirement R2 REPLACE: "the voltage protective relaying" WITH: "that generator voltage protective relaying" RATIONALE: Basically the same as outlined for the suggested R1 change above, but for voltage rather than frequency. FOR: Appendix 2 (graph) CHANGE: (raise the graph's 0 pu for 0.15 sec) TO: (15 pu for 0.15 sec, along with an appropriate footnote for consideration of preexisting equipment capability) RATIONALE: While the SDT cites FERC ORDER 661A and Appendix G in support of this value, FERC's paragraph 31 ruling agrees with NERC's proposed considerations they earlier discussed. NERC's proposal includes consideration for earlier-purchased wind turbines and their voltage ride-through capabilities, as well as provision for NERC to use their normal process to revise the ride-through capability. AECI believes the SDT should work to build industry consensus on an overall minimum voltage ride-through, or at least afford our industry the same considerations cited for wind turbines.
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
Yes
Group
Dominion
Mike Garton
Yes
Individual
David Jendras
Ameren
Yes
(1)On page 8, please delete “Measure M1 through M4” from the second paragraph of D.1.2 Data Retention. We understand that the entity must comply with the Requirements but the

Measures should not expand the scope of reliability standard requirements. (2)We request that the GVSDT add page numbers in the footer of the standard.
Individual
Karen Webb
City of Tallahassee
Yes
No
Individual
Scott Langston
City of Tallahassee
Yes
Individual
Darryl Curtis
Oncor Electric Delivery Company
N/A
The 60 calendar day requirement in R4 requiring a Generator Owner to provide its applicable generator protection trip settings to the Planning Coordinator or Transmission Planner within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings is too long. Settings that affect the performance of a system need to be communicated as quickly as possible and because of the critical nature of this data, prolonging system coordination could result in an unnecessary risk to the reliability of the Bulk Electric System. Oncor respectfully requests this time requirement be shortened to 30 days.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration agrees with the removal of R4. Our experience has been that ambiguities in reliability requirements force Compliance Enforcement Authorities to provide their own interpretations. This may result in uneven enforcement of the criteria or the development of a Compliance Application Notice, neither of which instill a sense of fairness in the process. Our hope is that the industry develop its own methods to predict voltage and frequency ride-through performance – which would be voluntary and supported by NERC experts.
Ingleside Cogeneration would like to point out that there are already 30 in-effect PRC and MOD standards – with at least four other project teams actively developing new modeling and Protection System requirements. In almost every case, the reliability intent is to ensure that

interconnected entities openly share relay settings, models, and operating information that reduces the risk to the greater whole. However, we do not believe that there is compelling evidence that adherence to these reliability standards correlates to improved reliability – therefore, the addition of one more PRC standard will not reduce BES risk. It is time to consider a more effective regulatory model to address generation/transmission coordination – one that recognizes that the subject matter is extraordinarily complex, with nearly more exceptions than commonalities. The focus would move from the enforcement of global mandates which do not always apply, to ensuring that GOs, PCs, and TPs are continually working the tradeoffs between BES stability and the threat to equipment damage. In this venue, NERC could serve as an expert arbiter to help resolve differences – a role that we believe will lead to the structural improvements necessary to reach our shared reliability goals.
Individual
Brett Holland
Kansas City Power & Light
Yes
This standard should apply to voltage protection and frequency protection only. It should not apply to volts/hertz or other generator protective elements. Volts/Hertz is specifically intended to protect transformers and generators from damage and the setting is based on the capability of those elements. The SDT has given guidance on Evaluating Protective Relay Settings however this creates a situation where protective settings might appear to be in conflict with the standard and during an audit a study or documentation must be presented to prove the relay setting on the generator side of the GSU is actually in compliance with the standard on the transmission side of the GSU based on the study documentation. Standard Requirements should be straight forward so compliance can be proved with the least amount of effort and documentation. The SDT should use the guidance on Evaluating Protective Relay Settings and produce Voltage Ride Through Time Duration curves on the generator side of the GSU because that is where the voltage source is for the existing generator protective relays.
Group
ACES Standard Collaborators
Jason Marshall
Yes
(1) We continue to be concerned that this standard is inconsistent with the stated vision of NERC regarding the transformation of the compliance process. As the standard is written, it has the potential to become another zero-defect standard in which compliance is paper driven and does little to support reliability. Because plants have lots of equipment, how will the auditor know that frequency and protective relay settings have been set according to the standard without first ensuring they have identified the appropriate relays to review? We can envision them wanting to see the list of all protective relays so that they can first verify that all voltage and frequency relays have been identified and then the list of settings based on this subset.

Furthermore, the language of the standard concerns us that a registered entity will be expected to provide evidence for any unit that trips to prove that it did not trip because of frequency or voltage protective relaying if the voltage and frequency remained within the associated envelopes of performance in the standard. (2) We are concerned that compliance with the standard will be inappropriately enforced based on the actual performance of a unit. The purpose statement says that the generator should “remain connected during frequency and voltage excursions”. Based on this purpose, we would be concerned that compliance with the standard would be assessed based on whether the generator rode through voltage and frequency excursions within the performance envelopes defined in the standard. This would be an inappropriate outcome because the requirements in the standard compel relay settings based on assumptions stated in the “Evaluating Protective Relay Settings” section of Attachment 2. If system conditions did not match the assumptions, how could the GO be held accountable? We believe that standard should make crystal clear that compliance is not to be assessed on actual performance because no GO can guarantee its units will ride through all voltage and frequency excursions defined in the performance envelope in the standard if the conditions vary from the assumptions. While we understand the drafting team did attempt to clarify this with a modification to the “Evaluating Protective Relay Settings” section in Attachment 2, the clarification is not enough. It only makes a statement about the assumptions to be used not how compliance should be assessed. We suggest application guidelines should be written to clearly describe how compliance would be met. We also suggest that an RSAW be developed to allow industry to provide feedback on compliance concerns. Finally, we recommend that the VSLs be modified to address these compliance concerns and to ensure consistency throughout the standard. (3) We continue to believe that requirements R3 and R4 are the types of requirements that the P81 project is attempting to retire. Both of these requirements fit more than one criteria in the project. Both are communication and documentation requirements and do little to support reliability by themselves. While we agree the GO needs to communicate equipment limitations, this type of requirement is administrative in nature and results in excessive paperwork burdens that NERC will monitor and enforce using a zero defect methodology. If it was necessary to have a requirement for every detail that needs to occur to plan and operate the electric grid, we would have millions of requirements. Part of the reason for these P81 criteria is to avoid the need to monitor compliance for every little detail like this. Furthermore, the VSLs associated with both requirements demonstrate that the requirements do little to support reliability. They anticipate the only violation is that compliance will be late. There are other options and alternatives that NERC and the Regions could utilize to ensure that the GO is communicating equipment limitations. At this point, we do not believe the drafting team has provided enough technical support to justify this type of requirement. (4) We continue to believe that the data retention period is too long and may cover time periods that include prior relay settings that are no longer relevant. What reliability benefit is provided by a Generator Owner retaining settings that are no longer valid? The proposed language compels the GO to retain data for six years which means that a GO may have retained evidence for settings that are no longer used. While the drafting team indicated that it used NERC boilerplate language in establishing the data retention period, there is nothing that requires the drafting team to use this language

requiring the data retention period to match the audit period. In contradiction, section 3.1.4.2 of Appendix 4C- Compliance Monitoring and Enforcement Program of the NERC Rules of Procedure is very clear that reliability standards may have a data retention period that is less than the audit period. Furthermore, countless standards use other data retention periods where it makes sense. For example, TOP-003-2 uses 90 days for one of the requirements based on the sheer volume of the data. The bottom line question should be: “Does a six year data retention period and the associated resources dedicating to maintaining this data for that long support reliability?” The answer is no and, thus, it should be changed. We recommend the data retention state that only the current relay settings should be retained. (5) The VSLs for R1 and R2 do not anticipate the situation where there is no equipment or regulatory limits. This could be remedied by making “and” into “and/or” in the VSLs. (6) Thank you for the opportunity to comment.
Group
Bonneville Power Administration
Jamison Dye
Yes
Individual
Bret Galbraith
Seminole Electric
The proposed PRC-024-1 Attachment 1 “Off Nominal Frequency Capability Curve” lists a table and plots a “No Trip Zone” for the Eastern Interconnection that inherently includes the FRCC Region. Currently, the FRCC Region has its own Generator Coordination Requirements document that sets out frequency capability curves that conflict with what is stated in Attachment 1 for the Eastern Interconnection. Seminole believes that Attachment 1 should take into consideration the specific frequency trip settings that the FRCC has listed in the FRCC’s internal compliance handbook, which can easily be submitted to NERC (if NERC does not already have access to this information). Requiring the FRCC to abide by these general Eastern Interconnection frequency trip settings may cause instability to the FRCC Region due to the FRCC’s peninsular geography, and therefore, Seminole reasons that a specific frequency capability curve, i.e., “no trip zone,” should be designated for the FRCC Region. In addition, underfrequency relays have been applied for years with a frequency setting and a timer for each setting, to provide for a step, piecewise underfrequency shedding plan. The proposed NERC frequency chart uses a linear characteristic with multiple frequencies and multiple differing times. Even the best available technology today does not support the NERC linear frequency chart.
Individual
Spencer Tacke
Modesto Irrigation District

No
I think adding the word “applicable” before the word “generator”, without defining applicable, is irresponsible and will lead to more confusion. I think in this case the word “applicable” may be being used as synonymous with the word “significant”. WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years learned to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2017. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the 1996 outage and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV. So I think it is very important to define what an “applicable” generator is for this standard, and I would recommend any generator 20 MVA or greater, connected at 60 kV or above.

Consideration of Comments

Generator Verification Project 2007-09
March 14, 2013

The Generator Verification Drafting Team thanks all commenters who submitted comments on the proposed revisions to PRC-024-1. This standard was posted for a 30-day public comment period from January 25, 2013 through February 25, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 29 sets of comments, including comments from approximately 90 different people from approximately 63 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT received a few excellent comments from stakeholders regarding clarifying revisions that would make the standard better. Based on these comments, the GVSDT made the following clarifying revisions to the standard:

- Added page numbers to first section of the standard.
- Added the word "generator" before "frequency protective relaying" (second line) in Requirement R1 and before "voltage protective relaying" (second line) in Requirement R2 so that the language mirrored the first line of each requirement.
- Added the phrase "for asynchronous generating units" to the first bullet of Requirement R1 to match the language in the analogous bullet 3 in Requirement R2.
- Added the phrase "the applicable generating unit(s)" to the third line of Requirement R2 to match the language in Requirement R1.
- Added the phrase "with generator frequency or voltage protective relays" to the second line of Requirement R3 to clarify the language.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

- Made minor revisions to Measures M3 and M4 to better conform with the language of the associated requirements.
- Removed mention of the Measures from the second paragraph of the Data Retention Section.
- Rearranged the wording of the VSLs for Requirement R1 and R2 to more accurately reflect the exceptions applicable under Requirement R3.
  - R1: The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
  - R2: The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
- Removed "for the data" from the end of the Severe VSL for Requirement R4 to have the language of each VSL align.
- Fixed an error in the text box identifying the "No Trip Zone" in Attachment 1.

Index to Questions, Comments, and Responses

1. The GVSDT has removed Requirement R4 from the standard. Stakeholders suggested that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as "sound engineering judgment" is subject to interpretation and vague. Do you agree with this revision? If not, please explain in the comment area below. .... 9~~8~~
2. Do you have any other comment, not expressed in questions above, for the GVSDT? .... 13~~12~~

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Kent Kujala	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Szulczewski		RFC	3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Terrill	Luminant Generation Company LLC	ERCOT	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

3.	M & A Electric Power Cooperative	SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative	SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.	SERC	1, 3
6.	Sho-Me Power Electric Cooperative	SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	John Allen	City Utilities of Springfield	SPP	1, 4
4.	Chandler Brown	Sunflower Electric	SPP	1
5.	Anthony Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
6.	Gary Condict	Sunflower Electric	SPP	1
7.	Alice Ireland	xcel energy	SPP	1, 3, 5, 6
8.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
9.	Valerie Pinamonti	AEP	SPP	1, 3, 5
10.	Paul Reynolds	Sunflower Electric	SPP	1
11.	Paul Von Hersenberg	Westar Energy	SPP	1, 3, 5, 6
12.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
13.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
14.	Brian Holmes	General Gentleman Station	SPP	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Electric Market Policy		5, 6, 1, 3
2.	Connie Lowe	NERC Compliance Policy	NPCC	5, 6
3.	Michael Crowley	Electric Transmission	SERC	1, 3
4.	Jeff Bailey	Nuclear	MRO	5, 6
5.	Sean Iseminger	F&H	SERC	5, 6
6.	Chip Humphrey	F&H	RFC	5, 6
7.	Randi Heise	NERC Compliance Policy	RFC	5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jason Marshall	ACES Standard Collaborators						X				

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

Additional Member		Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative Inc. and Southwest Transmission Cooperative Inc.	WECC	1, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3.	Tom Alban	Buckeye Power, Inc.	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
6.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member		Additional Organization	Region	Segment Selection
1.	Jim Burns	BPA, Transmission Technical Operations	WECC	1
2.	Steve Hitchens	BPA, Transmission Technical Operations	WECC	1
3.	Erika Doot	BPA, Power Services, Generation Support	WECC	3, 5, 6
4.	Sandra Takabayashi	BPA, Power Services, Federal Hydro Projects	WECC	3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
11.	Individual	Pamela R. Hunter	Southern Company - Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
12.	Individual	Thad Ness	American Electric Power	X		X		X	X				
13.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
14.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
15.	Individual	Daniela Hammons	CenterPoint Energy	X									
16.	Individual	Bill Fowler	City of Tallahassee			X							
17.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
18.	Individual	Michael Falvo	Independent Electricity System Operator		X								
19.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Chang G. Choi	City of Tacoma, Tacoma Public Utilities, Tacoma Power	X		X	X	X	X				
21.	Individual	David Jendras	Ameren	X		X		X	X				
22.	Individual	Karen Webb	City of Tallahassee					X					
23.	Individual	Scott Langston	City of Tallahassee	X									
24.	Individual	Darryl Curtis	Oncor Electric Delivery Company	X									
25.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
26.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
27.	Individual	Bret Galbraith	Seminole Electric			X	X	X	X				
28.	Individual	Spencer Tacke	Modesto Irrigation District			X	X	X					
29.	Individual	Robert Kenyon	NERC Compliance Investigations Group										

1. **The GVSDT has removed Requirement R4 from the standard. Stakeholders suggested that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as "sound engineering judgment" is subject to interpretation and vague. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of stakeholders agreed with the revision to the standard. One stakeholder suggested that the Requirement should be eliminated or merged into PRC-001 to avoid redundancy. The GVSDT does not believe that there is a redundancy. PRC-001 R3.1 requires each Generator Operator to coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. PRC-024, R4 requires each Generator Owner to provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit, within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless otherwise directed by the requesting Planning Coordinator or Transmission Planner.

Organization	Yes or No	Question 1 Comment
Entergy Services, Inc. (Transmission)	No	R4 as it was rewritten in draft 6 seems like a redundant sub requirement of PRC-001 R3. The type of protection described in R2 and R3 falls already in the "coordination" required category described in the NERC Technical Reference Document, "Power Plant and Transmission System Protection Coordination" Revision 1 - July 2010 http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf Furthermore the requirement fails to specify the accountability and responsibilities of the Transmission Planner/Transmission Operator in the "coordination" process in order to approve the relay setting changes. R4 should be eliminated or merged into PRC-001 R3 to avoid redundancies per FERC's instructions on eliminating redundancies.
Response: The GVSDT thanks you for your comment. As stated in the purpose, this standard is intended to "Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage		

Organization	Yes or No	Question 1 Comment
excursions" and is not for the coordination of protection settings among entities (PRC-001-1). There is no approved PRC-027 but even its draft is primarily related to coordination of interconnected elements for faults. Industry determined in the SAR, as a result of the Phase III and IV testing that the standard was needed. The GVSDT feels the two requirements are not the same. PRC-001 R3.1 requires each Generator Operator to coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. PRC-024, R4 requires each Generator Owner to provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit, within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless otherwise directed by the requesting Planning Coordinator or Transmission Planner.		
Modesto Irrigation District	No	
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration agrees with the removal of R4. Our experience has been that ambiguities in reliability requirements force Compliance Enforcement Authorities to provide their own interpretations. This may result in uneven enforcement of the criteria or the development of a Compliance Application Notice, neither of which instill a sense of fairness in the process. Our hope is that the industry develop its own methods to predict voltage and frequency ride-through performance - which would be voluntary and supported by NERC experts.
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Detroit Edison	Yes	
Duke Energy	Yes	
Luminant	Yes	

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Southwest Power Pool Standards Development Team	Yes	
Dominion	Yes	
ACES Standard Collaborators	Yes	
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
Southern Company - Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
City of Tallahassee	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group	Yes	
City of Tacoma, Tacoma Public Utilities, Tacoma Power	Yes	
Ameren	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Kansas City Power & Light	Yes	

2. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

Summary Consideration: The GVSDT received a few excellent comments from stakeholders regarding clarifying revisions that would make the standard better. Based on these comments, the GVSDT made the following clarifying revisions to the standard:

- **Added page numbers to the first section of the standard.**
- **Added the word "generator" before "frequency protective relaying" (second line) in Requirement R1 and before "voltage protective relaying" (second line) in Requirement R2 so that the language mirrored the first line of each requirement.**
- **Added the phrase "for asynchronous generating units" to the first bullet of Requirement R1 to match the language in the analogous bullet 3 in Requirement R2.**
- **Added the phrase "the applicable generating unit(s)" to the third line of Requirement R2 to match the language in Requirement R1.**
- **Added the phrase "with generator frequency or voltage protective relays" to the second line of Requirement R3 to clarify the language.**
- **Made minor revisions to Measures M3 and M4 to better align with the language of the associated requirements.**
- **Removed mention of the measures from the second paragraph of the Data Retention Section.**
- **Rearranged the wording of the VSLs for Requirement R1 and R2 to more accurately reflect the exceptions applicable under Requirement R3.**
  - **R1: The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.**
  - **R2: The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.**
- **Removed "for the data" from the end of the Severe VSL for Requirement R4 to have the language of each VSL align.**

- **Fixed an error in the text box identifying the "No Trip Zone" in Attachment 1.**

Organization	Question 2 Comment
Manitoba Hydro	(1) R2 - are the words 'the applicable generating units' missing after the word 'trip' in the third line? this would make the language consistent with the wording of R1. **Response: The GVSDT has added the phrase to clarify R2 as suggested. Also, the GVSDT notes that the first bullet of R1 and the third bullet of R2 had minor language differences. These were intended to be the same and the GVSDT has revised the first bullet in R1 to match the language in R2 by adding the phrase "..for asynchronous generating units.."** (2) R2- are the words 'of a location specific Transmission Planner's study' precise enough to know for certain what characteristics are being referred to and compliance measured? **Response: The GVSDT believes that the wording is clear. The Transmission Planner determines what study is required to specify less stringent voltage relay settings than those required to meet PRC-024, Attachment 2.** (3) R3 - is the word 'known' precise enough to know for certain what characteristics are being referred to and compliance measured? **Response: The GVSDT believes that the wording is clear. If an entity does not "know" about a limitation, they will not be able to document or communicate the limitation.** (4) R3, 3.1 - there is no notification requirement with respect to any modifications or upgrades that may remove the limitation - this seems to be a gap. **Response: The GVSDT believes that "modifications or upgrades" are covered under "repair" and "replacement". The GVSDT believes that any change in equipment limitation stated in R3.1 triggers communication to the Planning Coordinator or Transmission planner.** (5) M3 - the word 'documentation' should be changed to 'information'. **Response: The GVSDT believes 'documentation' is appropriate since the requirement is to**

Organization	Question 2 Comment
	"document" limitations. (6) M4 - does not seem to track the wording of R4 - measure should be that it 'provided applicable generator protection trip settings'.......and the word 'information' should be 'data'. **Response: The GVSDT has made the revision as suggested to have the measure more closely match the requirement.** (7) Compliance - same comment as previous re: use of the acronym CEA. **Response: The acronym is spelled out in the first line of item 1.1.** (8) VSLs, R1 and R2 - the way these requirements are worded it makes it seem as though the violation is that the GO has no documented limitation - that is not the violation, that would be a violation of R3. The violation for these two requirements would be a failure to set its relaying within the criteria of R1/R2. **Response: The GVSDT has revised the wording of the VSL as follows:** **R1. The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.** **R2. The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.** (9) VSLs, R2 - doesn't contemplate new change to language of R2 re: TP standards. **Response: The GVSDT believes that the VSL encompasses any voltage profile whether it is Attachment 2 or one provided by the Transmission Planner.** (10) VSLs, R3 - the timeline doesn't address any change other than the identification of the

Organization	Question 2 Comment
	limitation, i.e. but the timeline could run from repair, replacement. **Response: The GVSDT feels it is appropriate to tie the timeline to when the limitation was identified. The GVSDT believes that regardless of the time for repair and/or replacement is not the underlying concept in the VSL but communicating the limitation after its identification.** (11) VSLs, R4 - some refer to a 'written request' and some refer to a 'written request for the data' - these should be made consistent with the requirement language. **Response: The GVSDT has made the VSLs consistent by removing "for the data" from the Severe VSL.**
Response: The GVSDT thanks you for your comment. Please see responses above.	

ACES Standard Collaborators	(1) We continue to be concerned that this standard is inconsistent with the stated vision of NERC regarding the transformation of the compliance process. As the standard is written, it has the potential to become another zero-defect standard in which compliance is paper driven and does little to support reliability. Because plants have lots of equipment, how will the auditor know that frequency and protective relay settings have been set according to the standard without first ensuring they have identified the appropriate relays to review? We can envision them wanting to see the list of all protective relays so that they can first verify that all voltage and frequency relays have been identified and then the list of settings based on this subset. Furthermore, the language of the standard concerns us that a registered entity will be expected to provide evidence for any unit that trips to prove that it did not trip because of frequency or voltage protective relaying if the voltage and frequency remained within the associated envelopes of performance in the standard. **Response: The GVSDT thanks you for your comment. The standard is limited to the generator frequency or voltage protective relaying and is not applicable to other relays. The GVSDT believes that Requirement R1 and R2 are precise in that only generator voltage and frequency protective relays are involved. By definition, Protective Relays have voltage and/or current input and narrows the scope of R1 and R2. It is the Generator Owner's responsibility to determine which generator Protective Relay should be involved in the standard. There is no performance requirement in the standard that calls for a Generator Owner to prove that it did not trip for any transmission event.** (2) We are concerned that compliance with the standard will be inappropriately enforced based on the actual performance of a unit. The purpose statement says that the generator should "remain connected during frequency and voltage excursions". Based on this purpose, we would be concerned that compliance with the standard would be assessed based on whether the generator rode through voltage and frequency excursions within the performance envelopes defined in the standard. This would be an inappropriate outcome because the requirements in the standard compel relay settings based on assumptions stated in the "Evaluating Protective Relay Settings" section of Attachment 2. If system conditions did not match the assumptions, how could the GO be held accountable? We believe that standard should make crystal clear that compliance is not to be assessed on actual performance because no GO can guarantee its units will ride through all voltage and frequency excursions defined in the performance envelope in the

	standard if the conditions vary from the assumptions. While we understand the drafting team did attempt to clarify this with a modification to the "Evaluating Protective Relay Settings" section in Attachment 2, the clarification is not enough. It only makes a statement about the assumptions to be used not how compliance should be assessed. We suggest application guidelines should be written to clearly describe how compliance would be met. We also suggest that an RSAW be developed to allow industry to provide feedback on compliance concerns. Finally, we recommend that the VSLs be modified to address these compliance concerns and to ensure consistency throughout the standard. **Response: The GVSDT thanks you for your comments. The GVSDT believes that the standard is now abundantly clear that it is only a relay setting standard and it is not a generator performance standard. The GVSDT believes that the requirements set forth in the standard only call for the Generator Owner to sets its generator protective relaying per the Attachments or, in the case of R2, a less stringent voltage profile provided by the Transmission Planner and provide others information on limitations. Your suggestions regarding development of application guidelines and an RSAW will be provided to the appropriate NERC staff.** (3) We continue to believe that requirements R3 and R4 are the types of requirements that the P81 project is attempting to retire. Both of these requirements fit more than one criteria in the project. Both are communication and documentation requirements and do little to support reliability by themselves. While we agree the GO needs to communicate equipment limitations, this type of requirement is administrative in nature and results in excessive paperwork burdens that NERC will monitor and enforce using a zero defect methodology. If it was necessary to have a requirement for every detail that needs to occur to plan and operate the electric grid, we would have millions of requirements. Part of the reason for these P81 criteria is to avoid the need to monitor compliance for every little detail like this. Furthermore, the VSLs associated with both requirements demonstrate that the requirements do little to support reliability. They anticipate the only violation is that compliance will be late. There are other options and alternatives that NERC and the Regions could utilize to ensure that the GO is communicating equipment limitations. At this point, we do not believe the drafting team has provided enough technical support to justify this type of requirement. **Response: The GVSDT thanks you for your comment. The GVSDT believes that R3 and R4 are necessary for reliability and appropriate. The SDT has reviewed the criteria for removing**

	requirements per Paragraph 81 and determined that the requirements of PRC-024 do not meet the applicable criteria. In order to be considered for removal, a requirement has to meet Item A as well as at least one part of Item B (see P81 team criteria document, provided in that project's Technical White Paper). The requirements of PRC-024 do not meet Item A and therefore are not eligible for inclusion in P81 process. (4) We continue to believe that the data retention period is too long and may cover time periods that include prior relay settings that are no longer relevant. What reliability benefit is provided by a Generator Owner retaining settings that are no longer valid? The proposed language compels the GO to retain data for six years which means that a GO may have retained evidence for settings that are no longer used. While the drafting team indicated that it used NERC boilerplate language in establishing the data retention period, there is nothing that requires the drafting team to use this language requiring the data retention period to match the audit period. In contradiction, section 3.1.4.2 of Appendix 4C- Compliance Monitoring and Enforcement Program of the NERC Rules of Procedure is very clear that reliability standards may have a data retention period that is less than the audit period. Furthermore, countless standards use other data retention periods where it makes sense. For example, TOP-003-2 uses 90 days for one of the requirements based on the sheer volume of the data. The bottom line question should be: "Does a six year data retention period and the associated resources dedicating to maintaining this data for that long support reliability?" The answer is no and, thus, it should be changed. We recommend the data retention state that only the current relay settings should be retained. **Response: The GVSDT thanks you for your comment. The GVSDT believes the data retention requirements are necessary to enable verification of compliance from one period to the next.** (5) The VSLs for R1 and R2 do not anticipate the situation where there is no equipment or regulatory limits. This could be remedied by making "and" into "and/or" in the VSLs. **Response: The GVSDT revised the VSLs for R1 and R2 to address your concern.** (6) Thank you for the opportunity to comment.

Response: The GVSDT thanks you for your comment. Please see responses above.

Ameren	(1)On page 8, please delete "Measure M1 through M4" from the second paragraph of D.1.2 Data Retention. We understand that the entity must comply with the Requirements but the Measures should not expand the scope of reliability standard requirements. **Response: The GVSDT has removed the measures as suggested for clarity.** (2)We request that the GVSDT add page numbers in the footer of the standard. **Response: We have added page numbers as requested.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
American Electric Power	AEP recommends that the time allowed to meet R 3.1 be extended to 60 calendar days, aligning it with R4, thereby making the timing requirements of the standard more consistent throughout. **Response: The GVSDT does not believe that the two requirements are linked and therefore the timing requirements can be different. R4 allows for additional time because it deals with a request from another entity.** R2: Regarding the language "If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying", we believe the intent is to allow the GO to set its protective relaying within the PRC-024 no-trip zone and remain compliant so long as the Transmission Planner's less stringent requirements is met. However it is not made explicitly clear by doing so that one would still be fully compliant with PRC-024. We recommend making this explicitly clear within R2.Suggest rewording the first sentence of R2 to state the following: "Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) that remains within the "no trip zone" of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant." **Response: The GVSDT believes the existing wording makes it clear that the GO may set its protective relaying based on a less stringent requirement if so allowed by the Transmission Planner.**

<table>
<tr><td colspan="2">Response: The GVSDT thanks you for your comment. Please see responses above.</td></tr>
<tr><td>CenterPoint Energy</td><td>CenterPoint Energy remains concerned with truncating the Voltage Ride-Through Time Duration Curve (Attachment 2) at 4 seconds due to coordination with undervoltage load shedding systems (UVLS). For coordination of UVLS with any generator voltage protective relays, CenterPoint Energy recommends the curve be extended to at least 10 seconds at 0.90 per unit POI Voltage. CenterPoint Energy does not believe such a change would be controversial, as the GVSDT states in the Consideration of Comments (Draft 5) that “Stakeholders pointed out that transmission systems are designed to operate between 90% to 110%.”</td></tr>
<tr><td colspan="2">Response: The GVSDT thanks you for your comment. The team has coordinated our voltage curve and time points with the drafting team working on PRC-025, Generator Relay Loadability. The voltage characteristics in PRC-025 deal with steady state conditions, which we have coordinated at 4 seconds. At that point, the voltage excursion has ended for applicability to PRC-024.</td></tr>
<tr><td>Associated Electric Cooperative, Inc. - JRO00088</td><td>FOR: Requirement R1,REPLACE: "the frequency protective relaying" WITH: "that generator frequency protective relaying" RATIONALE: SDT intent, with the subordinate bulleted exceptions, appears to provide for exception of necessary overriding conditions within the "no trip zone" for which the "generator frequency protective relaying" is permitted to necessarily go ahead an trip the unit. This suggested change is an attempt to strengthen the linkage between the qualifying R1 "has generator frequency protective relaying activated...", and those bulleted exceptions in order to calm industry concern that those bullets form the only permissible set of unit protective relaying conditions that are allowed to trip the trip (protect) the unit and its underlying equipment when operating within the units' "no trip zone" of frequency conditions.

Response: The GVSDT has made the suggested revision for clarity.

FOR: Requirement R2REPLACE: "the voltage protective relaying" WITH: "that generator voltage protective relaying" RATIONALE: Basically the same as outlined for the suggested R1 change above, but for voltage rather than frequency.

Response: The GVSDT has made the suggested revision for clarity.

FOR: Appendix 2 (graph)CHANGE: (raise the graph's 0 pu for 0.15 sec)TO: (15 pu for 0.15 sec, along with an appropriate footnote for consideration of preexisting equipment capability)RATIONALE: While the SDT cites FERC ORDER 661A and Appendix G in support of this</td></tr>
</table>

	value, FERC's paragraph 31 ruling agrees with NERC's proposed considerations they earlier discussed. NERC's proposal includes consideration for earlier-purchased wind turbines and their voltage ride-through capabilities, as well as provision for NERC to use their normal process to revise the ride-through capability. AECI believes the SDT should work to build industry consensus on an overall minimum voltage ride-through, or at least afford our industry the same considerations cited for wind turbines. **Response: The GVSDT believes that industry consensus has been achieved with respect to the elements of this standard. The standard had been posted six times and balloted five times.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Modesto Irrigation District	I think adding the word "applicable" before the word "generator", without defining applicable, is irresponsible and will lead to more confusion. I think in this case the word "applicable" may be being used as synonymous with the word "significant". WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years learned to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2017.Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the 1996 outage and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV. So I think it is very important to define what an "applicable" generator is for this standard, and I would recommend any generator 20 MVA or greater, connected at 60 kV or above.
Response: The GVSDT thanks you for your comment. The word "applicable" means any generator that meets the NERC registry criteria.	

Ingleside Cogeneration LP	Ingleside Cogeneration would like to point out that there are already 30 in-effect PRC and MOD standards - with at least four other project teams actively developing new modeling and Protection System requirements. In almost every case, the reliability intent is to ensure that interconnected entities openly share relay settings, models, and operating information that reduces the risk to the greater whole. However, we do not believe that there is compelling evidence that adherence to these reliability standards correlates to improved reliability - therefore, the addition of one more PRC standard will not reduce BES risk. It is time to consider a more effective regulatory model to address generation/transmission coordination - one that recognizes that the subject matter is extraordinarily complex, with nearly more exceptions than commonalities. The focus would move from the enforcement of global mandates which do not always apply, to ensuring that GOs, PCs, and TPs are continually working the tradeoffs between BES stability and the threat to equipment damage. In this venue, NERC could serve as an expert arbiter to help resolve differences - a role that we believe will lead to the structural improvements necessary to reach our shared reliability goals.
Response: The GVSDT thanks you for your comment. We would like to mention that the current version of PRC-006 (Underfrequency Load Shedding) depends on PRC-024 to ensure that Generator Operators set their frequency protection to coordinate with UFLS programs or make the appropriate notifications for those cases where that can't be accomplished. The GVSDT suggests that you bring your ideas to the attention of the Standards Committee by submitting a new SAR. The concepts you discuss are outside the scope of this SDT.	
City of Tacoma, Tacoma Public Utilities, Tacoma Power	It is not completely clear how to implement Requirement R2 given the information contained in Attachment 2. Specifically, clarification is requested on the following two issues. A. In Attachment 2, what issue is Curve Detail 3 intended to address? Is it suggesting that definite-time voltage elements should be used, instead of inverse time elements, unless detailed analysis is performed? It is not clear if Curve Detail 3 is intended to afford entities additional flexibility or to require them to conduct more detailed analysis. **Response: Detail 3 is meant to clarify that the curves in Attachment 2 are demonstrating cumulative time above or below the defined voltage levels instead of a voltage-time envelope. When analyzing an event, you cannot simply overlay a recorded voltage trace on top of Attachment 2, but rather determine the cumulative time the voltage was above or below the**

	defined voltages (as expressed in the Detail 3 example). The GVSDT does not mean to suggest the use of any particular type of protection timing. B. In Attachment 2, is the section titled "Evaluating Protective Relay Settings" intended to determine the per unit voltage base, at the generator terminals, for the Voltage Ride-Through Time Duration Curve? **Response: The section "Evaluating Protective Relay Settings" does not specify the per unit voltage base. That is specified in Curve Detail #1.** Under Measurement M3, change "manufacturer's advisory" to "manufacturer's advice" to be consistent with Requirement R3. **Response: The GVSDT agrees and will change the wording in Measurement M3 to say "manufacturer's advice".** In Attachments 1 and 2, do the "no trip zones" include the lines? In other words, for the Western Interconnection, if a frequency element was set to 57.2 Hz, would an operating time of 0.75 seconds be acceptable per the standard, or does the operating time have to be above 0.75 seconds? (A similar question could be asked for the Voltage Ride-Through Time Duration Curve.) **Response: In Attachment 1 the "no trip zone" does not include the lines. The GVSDT apologizes that the text box with that clarification was improperly sized and hid those words in the most recently published version. The GVSDT will correct the error in the next posting. In Attachment 2 the "no trip zone" does include the lines since doing otherwise would allow tripping for transmission voltages of 0.0 per unit during a fault.** In Attachment 2, under "Evaluating Protective Relay Settings," change "use either the following..." to "use either of the following..." **Response: The GVSDT believes the wording is correct as published. The intent is that the evaluator "…use either the following assumptions…" (i.e. the four assumptions listed) "…or loading conditions that are believed to be the most probable…"**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Entergy Services, Inc.	PRC-024-1 previous draft placed the burden of complying with the standard solely on the GO. This new draft places the bulk of ensuring compliance on the GO while providing a different criteria or

(Transmission)	“exemption” given by the Transmission Planner. If that is the case, the Planner should have a joint obligation to ensure the GO/GOP is successful in meeting and achieving compliance spelled out in the standard. Additionally, the Planner would be the best party capable of determining “which voltage protective relaying setting does not trip as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. Applicability of the standard should also include the Transmission Planner. **Response: The GVSDT disagrees that the Transmission Planner should be included as an Applicable entity since their activities are optional, not mandatory. With regard to the evaluation of the performance of the generator Protection System, the standard does not prevent the Generator Owner from requesting assistance from the Transmission Planner. However, as the owner of the Protection System, the Generator Owner is responsible for ensuring that an evaluation is performed.** R2 also lacks a mechanism(how the study is initiated and why, study request timeframe, study response timeframe, etc) whereby the Transmission Planner provides the “less stringent” voltage protection requirements so the GO can then determine when they need to follow Attachment 2 or the Planner’s study or have the Planner determine the criteria first. The requirement should be clearer and more details should be added. **Response: The provision of a “less stringent” location-specific voltage profile is solely at the option of the Transmission Planner. As such, the GVSDT does not believe it would be appropriate to specify a mechanism for this activity.** R3 objectives state that the GO shall provide equipment limitations to the Planner within 30 days of a request or change. PRC-024-1 R3 does not provide any value when MOD-010, MOD-012 and MOD-025, MOD-026 and MOD-027 appear to address these issues. R3 needs to be clarified with more details to avoid possible redundancies with the MOD standards. **Response: Requirement R3 does not address “requests”. The GVSDT does not see any redundancy between the generator frequency and voltage protection settings of interest in this standard and the requirements of MOD-010, MOD-025, MOD-026, or MOD-027. The reporting requirements of MOD-012 are determined by the “Regional Reliability Organizations” in MOD-013, which may or may not overlap with PRC-024.**

Response: The GVSDT thanks you for your comment. Please see responses above.	
Detroit Edison	Regarding Footnote 1 for R1, are protective functions within control systems that measure frequency from a non-electrical input such as speed sensors, included as "protective relaying"? **Response: The intent of the GVSDT is that the scope of protective functions be consistent with those defined as part of a generator protection system in PRC-005.** Please clarify that this standard pertains only to generator protective functions that respond exclusively to voltage and/or frequency, but not current. **Response: The GVSDT believes that this is adequately clear as written in footnote 1. …" within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs…".** Please adjust Attachment 1 Eastern Interconnection frequency data point exponents on page 13 so that they are completely visible. Please verify for Attachment 2 Voltage Curve that continuous operation is expected greater than 0.90 pu. and less than 1.10 pu. **Response: The exponents in the Attachment 1 data table for the Eastern Interconnection in the clean version of PRC-024 published on the NERC website appear visible to the GVSDT. PRC-024 only defines how the Generator Owner should set generator protection to address excursions. Settings for steady state operation are not defined by this standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.	
Oncor Electric Delivery Company	The 60 calendar day requirement in R4 requiring a Generator Owner to provide its applicable generator protection trip settings to the Planning Coordinator or Transmission Planner within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings is too long. Settings that affect the performance of a system need to be communicated as quickly as possible and because of the critical nature of this data, prolonging system coordination could result in an unnecessary risk to the reliability of the Bulk Electric System. Oncor respectfully requests this time requirement be shortened to 30 days.
Response: The GVSDT thanks you for your comment. The GVSDT had to balance opinions that the reporting period is too short	

with those that it is too long and believes 60 days is a reasonable compromise. The GVSDT considers this standard to be on a unit basis and that 60 days should be adequate for any single unit.	
Seminole Electric	The proposed PRC-024-1 Attachment 1 "Off Nominal Frequency Capability Curve" lists a table and plots a "No Trip Zone" for the Eastern Interconnection that inherently includes the FRCC Region. Currently, the FRCC Region has its own Generator Coordination Requirements document that sets out frequency capability curves that conflict with what is stated in Attachment 1 for the Eastern Interconnection. Seminole believes that Attachment 1 should take into consideration the specific frequency trip settings that the FRCC has listed in the FRCC's internal compliance handbook, which can easily be submitted to NERC (if NERC does not already have access to this information). Requiring the FRCC to abide by these general Eastern Interconnection frequency trip settings may cause instability to the FRCC Region due to the FRCC's peninsular geography, and therefore, Seminole reasons that a specific frequency capability curve, i.e., "no trip zone," should be designated for the FRCC Region. In addition, underfrequency relays have been applied for years with a frequency setting and a timer for each setting, to provide for a step, piecewise underfrequency shedding plan. The proposed NERC frequency chart uses a linear characteristic with multiple frequencies and multiple differing times. Even the best available technology today does not support the NERC linear frequency chart.
Response: The GVSDT thanks you for your comment. The GVSDT received the UFLS data points for PRC-006 for the FRCC Region as well as others. We developed the frequency curve contained in Attachment 1 of PRC-024 to coordinate with PRC-006 to have generators remain on-line so that the UFLS program can shed load to return frequency to near-nominal or nominal frequency. PRC-024 is a new, continent-wide reliability standard that sets the "no trip zones" for all generators in an Interconnection. By meeting the criteria in PRC-024, FRCC region generators will remain on-line for a period of time that ensures operation of the UFLS system resulting in greater stability for the region. The Implementation Plan allows for a five-year, phased implementation of the relay settings. **Please note that your second paragraph addresses UFLS set points. The curves in PRC-024 only deal with generator relay settings and provide the "no trip zone" for operation during off-nominal frequency conditions.**	
Kansas City Power & Light	This standard should apply to voltage protection and frequency protection only. It should not apply to volts/hertz or other generator protective elements. Volts/Hertz is specifically intended to

	protect transformers and generators from damage and the setting is based on the capability of those elements. The SDT has given guidance on Evaluating Protective Relay Settings however this creates a situation where protective settings might appear to be in conflict with the standard and during an audit a study or documentation must be presented to prove the relay setting on the generator side of the GSU is actually in compliance with the standard on the transmission side of the GSU based on the study documentation. Standard Requirements should be straight forward so compliance can be proved with the least amount of effort and documentation. The SDT should use the guidance on Evaluating Protective Relay Settings and produce Voltage Ride Through Time Duration curves on the generator side of the GSU because that is where the voltage source is for the existing generator protective relays.
Response: The GVSDT thanks you for your comment. **Volts/Hertz relays are applicable under this standard because they respond to system voltage excursions. These relays are to be evaluated at 60 Hz (see item 4 under Curve Details for Attachment 2). When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.** **The GVSDT does not believe that there is any conflict between the "Evaluating Protective Relay Settings" section in Attachment 2. The GVSDT has provided this information at the request of stakeholders during pervious postings and has made revisions for clarity. The GVSDT believes that stakeholder consensus has been achieved with respect to this language.**	
Public Service Enterprise Group	Yes. For generators without frequency or voltage protective relaying, R1 and R2 respectively do not require these relays to be installed per footnote 1. However, R3 could be interpreted to require generators without such relaying to be required to comply with R3 because it applies to a generator limitation that "prevents an applicable generating unit from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice." We have received an e-mail from the drafting team NERC coordinator for this project that this is NOT the intent of R3 - R3 is only intended to apply to generators that HAVE frequency and/or voltage protective relaying installed. We ask that the SDT confirm this understanding. If this is the SDT's intent we recommend that R3 be clarified as follows: Each Generator Owner shall document each known regulatory or equipment limitation3 that prevents an applicable generating unit WITH GENERATOR FREQUENCY OR VOLTAGE

	PROTECTIVE RELAYS from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. Alternative wording to clarify R3's intent that it does not apply to generators without frequency or voltage protective relaying would be acceptable.
Response: The GVSDT thanks you for your comment. This is the intent of the SDT. The wording you suggested has been added to R3 to clarify this intention. The SDT believes that this addition does not substantially change the requirement, but will merely enhance the understanding. The GVSDT feels that if there are no relays activated that can trip the unit under R1 or R2 then relay setting under R3 should not be an issue.	

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 of PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from February 29 – March 29, 2012.
8. Draft 4 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from September 28 – October 31, 2012.
9. Draft 5 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from December 12, 2012 – January 11, 2013.
10. Draft 6 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from January 25 through February 28, 2013.

Proposed Action Plan and Description of Current Draft:

This is the seventh draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This sixth posting is for a 10-day recirculation ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
5. BOT adoption.	May 2013
6. File with regulatory authorities.	June 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings

2. **Number:** **PRC-024-1**

3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   5.1. In those jurisdictions where regulatory approval is required:

   5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

   5.2. In those jurisdictions where regulatory approval is not required:

   5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[2]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[3] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

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[3] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

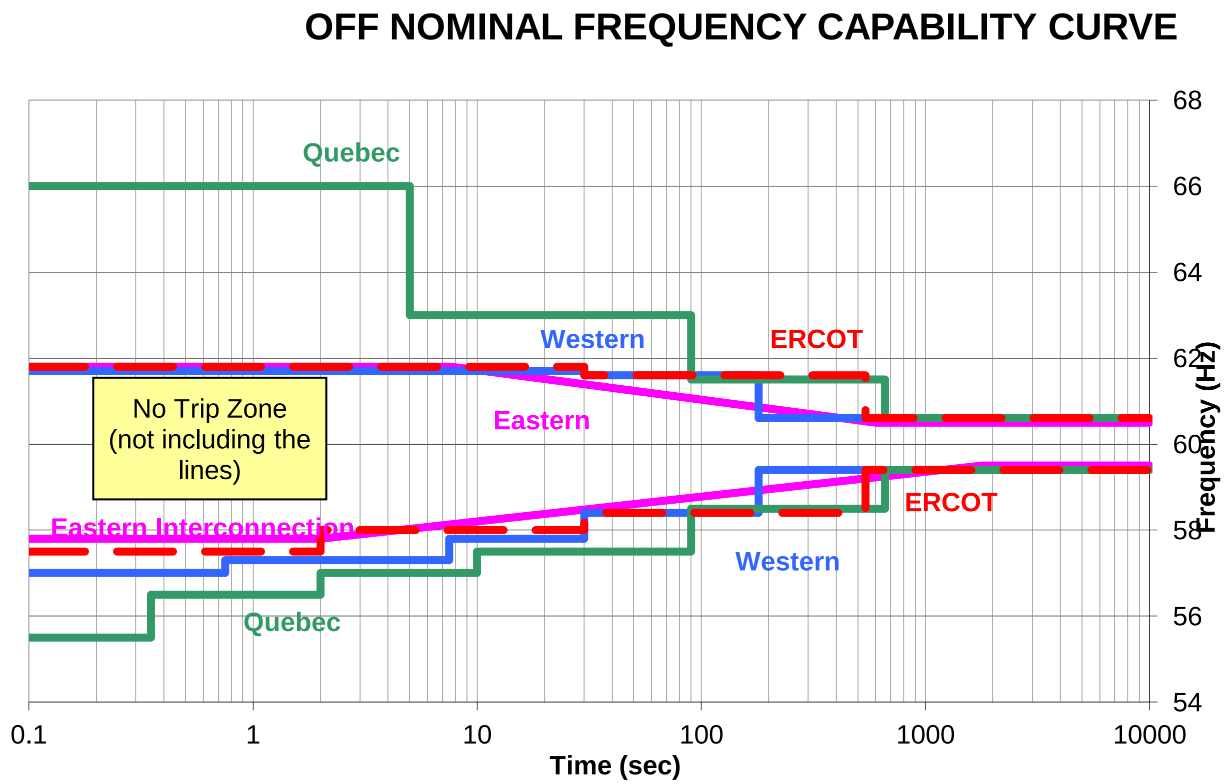
Version History

Version	Date	Action	Change Tracking

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

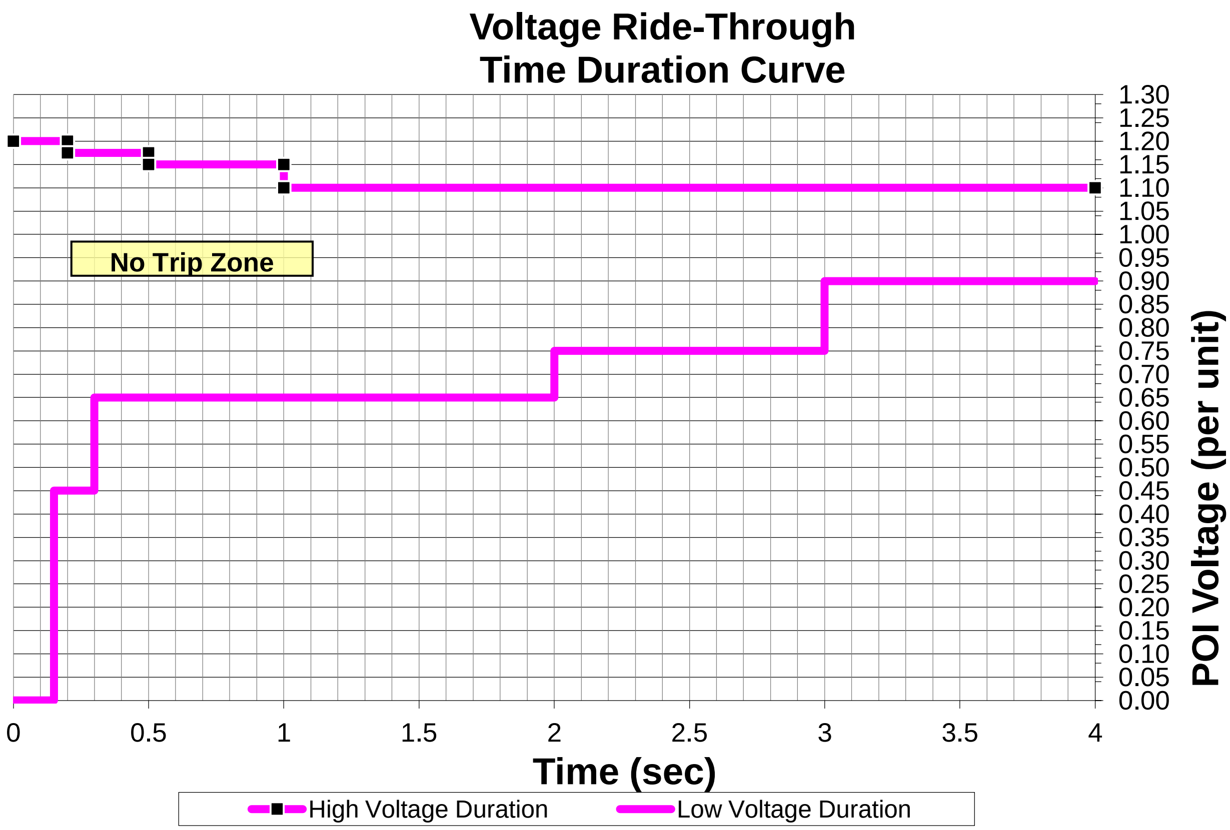
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 of PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from February 29 – March 29, 2012.
8. Draft 4 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from September 28 – October 31, 2012.
9. Draft 5 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from December 12, 2012 – January 11, 2013.

~~9.~~10. Draft 6 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from January 25 through February 28, 2013.

Proposed Action Plan and Description of Current Draft:

This is the ~~sixth~~ seventh draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This sixth posting is for a ~~30~~10-day ~~comment and successive~~recirculation ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. Develop responses to comments and develop sixth version draft standard.~~	~~January 2013~~

~~2. Post response to comments and conduct successive ballot.~~	~~February 2013~~
~~3. Develop responses to ballot comments.~~	~~March 2013~~
~~4. Post responses to comments and conduct recirculation ballot.~~	~~April 2013~~
5. BOT adoption.	May 2013
6. File with regulatory authorities.	June 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** **PRC-024-1**
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
   - **4.1.** Generator Owner
5. **Effective Date:**
   - **5.1.** In those jurisdictions where regulatory approval is required:
     - **5.1.1** By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
     - **5.1.2** By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
     - **5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
     - **5.1.4** By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
   - **5.2.** In those jurisdictions where regulatory approval is not required:
     - **5.2.1** By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1]~~[1]~~ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[2]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[3] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

[3] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice~~sory~~.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4~~, Measures M1 through M4~~; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, ~~has no documented and communicated regulatory or equipment limitation per Requirement R3 and~~ failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, ~~has no documented and communicated regulatory or equipment limitation per Requirement R3 and~~ failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.~~ for the data.~~

E. Regional Variances

None

F. Associated Documents

None

Version History

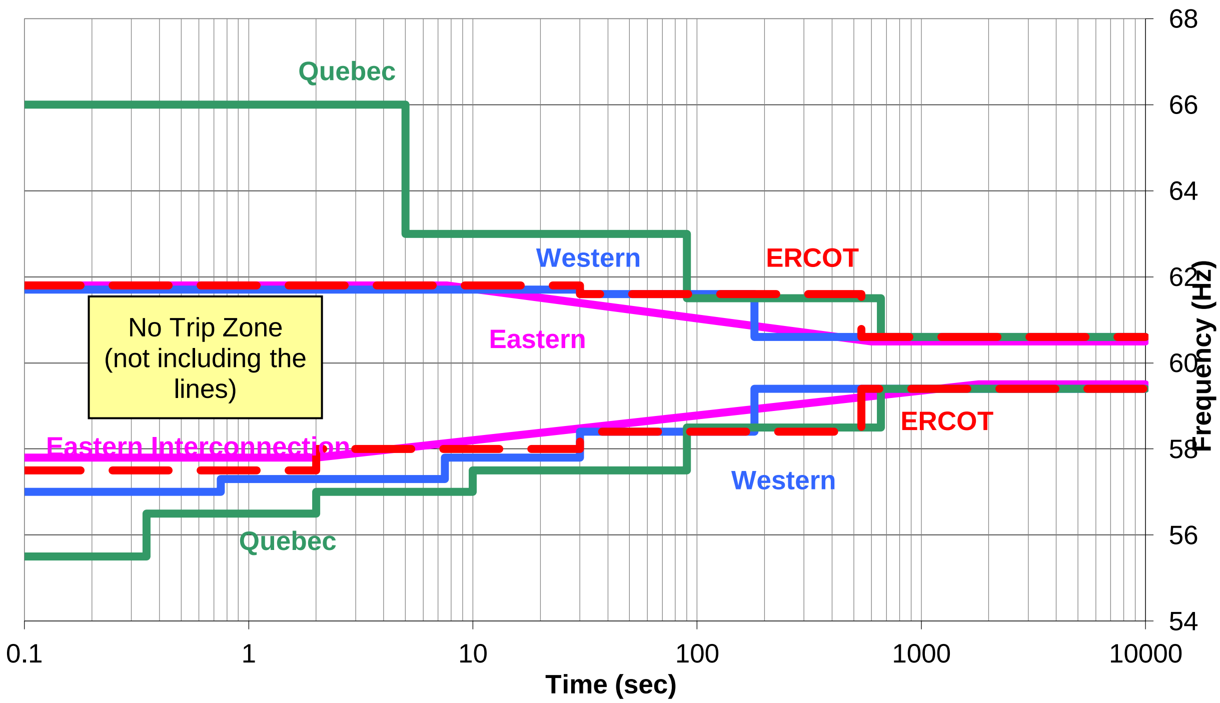
Version	Date	Action	Change Tracking

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
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Western Interconnection

High Frequency Duration		Low Frequency Duration	
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≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

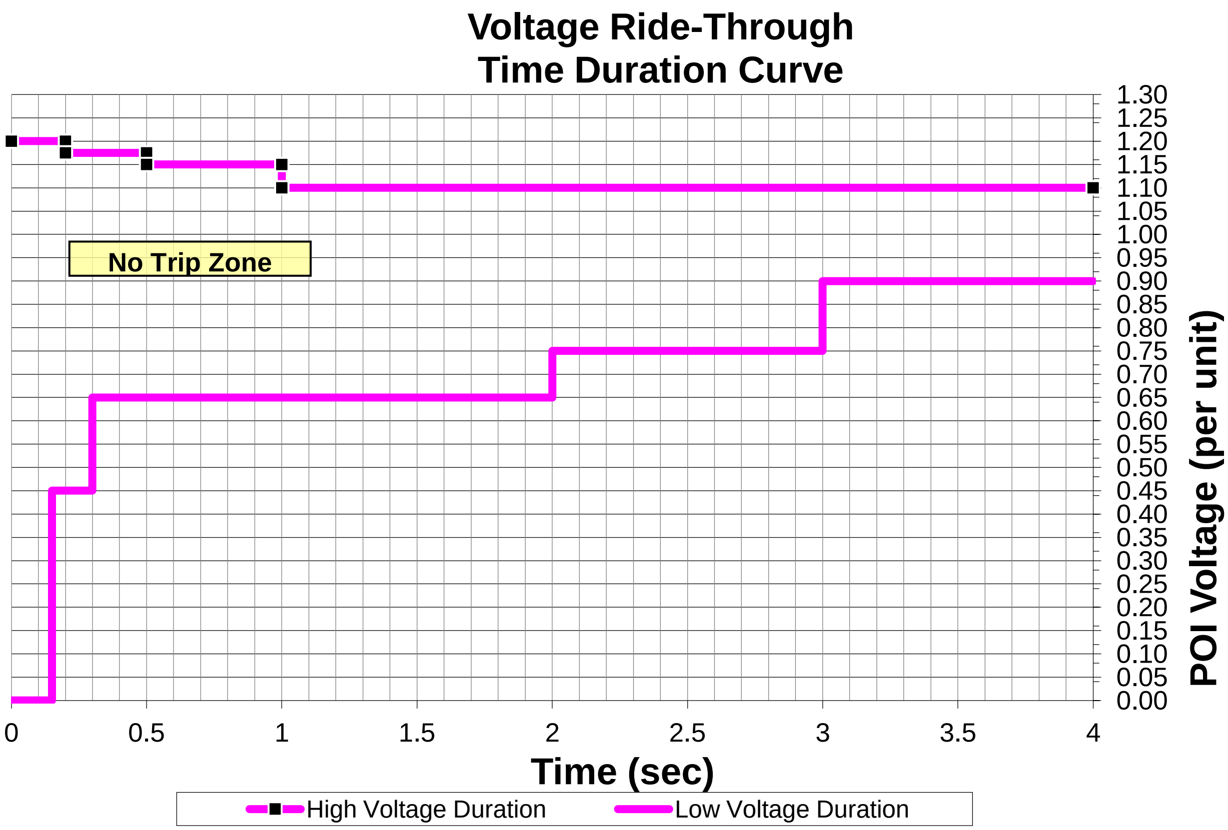
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Frequency and Voltage Protective Relay Settings

Approvals Required

PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024-1 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to

such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

In those jurisdictions where regulatory approval is not required:

- By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, and R4 involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024-1		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 1787 states "… the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping."	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R2 and the voltage ride through curves in PRC-024 Attachment 2 accomplish this. While the curves were developed based on three phase normally cleared faults located at a generating plant substation (the most severe condition for generating equipment), the curves cover voltages depressed as low as 0.65 per unit for two seconds, which the GVSDT feels will cover the Category B and C events of concern to the Commission. Requirement R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented regulatory or technical reasons, but directs those generators to communicate that limitation to the PC and TP so its performance can be modeled correctly.
Paragraph 1787 also states "… the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented regulatory limitations. The GVSDT believes that NRC requirements qualify as regulatory limitations for the purposes of this standard.

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RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Generator Verification Standard Drafting Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF for PRC-024-1:
There are four requirements in PRC-024-1. Two of the Requirements (R1 and R2) were assigned a "Medium" VRF and the remaining two requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure a proper frequency "no-trip" operating window is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency "no-trip" operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to ensure proper voltage "no-trip" criteria is a requirement in the planning time frame that, if violated, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Therefore the assigned "Medium" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage "no-trip" criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The "Medium" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The "Lower" VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R4:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a "Lower" VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore the assigned "Lower" VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The "Lower" VRF assigned is based on the reliability objective specified.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in PRC-024-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for PRC-024-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL guidelines are satisfied by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Standards Announcement

Project 2007-09 Generator Verification
PRC-024-1

Recirculation Ballot is now open through Wednesday, March 27, 2013

Now Available

A recirculation ballot of **PRC-024-1** is now open **through 8 p.m. Eastern on Wednesday, March 27, 2013**.

Background information for this project can be found on the project page.

Instructions
In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the recirculation ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps
Voting results will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-09 Generator Verification PRC-024-1

Recirculation Ballot Results

Now Available

A recirculation ballot of **PRC-024-1** concluded at **8 p.m. Eastern on Wednesday, March 27, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the recirculation ballot.

Approval
Quorum: 81.33% Approval: 89.44%

Background information for this project can be found on the project page.

Next Steps

The standard will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Ballot Results	
Ballot Name:	Project 2007-09 PRC-024-1 Recirculation Ballot March 2013_in
Ballot Period:	3/18/2013 - 3/27/2013
Ballot Type:	Initial
Total # Votes:	257
Total Ballot Pool:	316
Quorum:	**81.33 % The Quorum has been reached**
Weighted Segment Vote:	89.44 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	82	1	50	0.847	9	0.153	8	15
2 - Segment 2.	6	0.5	5	0.5	0	0	0	1
3 - Segment 3.	68	1	46	0.885	6	0.115	4	12
4 - Segment 4.	25	1	15	0.833	3	0.167	2	5
5 - Segment 5.	76	1	47	0.887	6	0.113	7	16
6 - Segment 6.	42	1	30	0.909	3	0.091	1	8
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	5	0.5	1	0.1	0	2
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.7	7	0.7	0	0	0	0
Totals	**316**	**7**	**207**	**6.261**	**28**	**0.739**	**22**	**59**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	paul B johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden	Abstain	
1	Central Maine Power Company	Kevin L Howes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D Schellberg		
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones		
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Larry G Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	

3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Associated Electric Cooperative, Inc.	Brad Haralson		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Constellation Power Source Generation, Inc.	Amir Y Hammad	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	

5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Siemens PTI	Edwin Cano		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bo Jones		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda L Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		

6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen		
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton	Affirmative	
8		Brendan Kirby	Affirmative	
8		James A Maenner		
8		Edward C Stein		
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Exhibit F

Standard Drafting Team Roster for NERC Standards Development Project 2007-09

Project 2007-09 Generator Verification

Standard Drafting Team

Name and Title	Company and Address	Contact Info	Bio
Lee Y. Taylor - Chair System Operations Manager	Southern Company Services, Inc. 600 North 18th Street P.O. Box 2641 Birmingham, Alabama 35291	(205) 257-7467 ltaylor@ southernco.com	Lee has a Bachelor of Electrical Engineering degree from Auburn University, and a M.S.E.E degree from the University of Alabama at Birmingham, and has over 30 years experience with Southern Company. Upon graduation from Auburn, he joined the Power Delivery Department of Alabama Power Company. He was a part time Adjunct Professor at the University of Alabama at Birmingham from 1987 to 1992. In 1988, he joined Southern Company Services where he worked in the Electrical Engineering Services Department and the Energy Management System Services Department. From 1996 – 2008, Lee worked in the Transmission Planning Department where he was involved in reactive planning and voltage control and stability studies for the Southern Company grid. Lee also was a member of the NERC System Planning, Design, and Studies Team in support of the 2003 Northeast blackout investigation. Currently, Lee is the System Operations Manager responsible for the Operations Planning group in the Bulk Power Operations department. The Operations Planning group provides support to Southern Company's Power Coordination Center which monitors and ensures bulk power transmission network security for Southern Company on a 24x7 basis. Mr. Taylor is a registered Professional Engineer in the State of Alabama.
David Kral – Vice-Chair Principal Engineer	Xcel Energy, Inc. 1518 Chestnut Avenue N. Minneapolis, Minnesota 55403	(612) 630-4266 david.s.kral@ xcelenergy.com	David Kral is a Principal Engineer in the Technical Resources & Compliance Department of Xcel Energy. He supports the generating plants in Xcel's Northern States Power (NSP) operating company on issues with generators and the electrical auxiliary systems. In particular, David provides expertise on excitation systems and generator protection. David also serves as a liaison with the Transmission area of NSP on technical issues. David is the Chairman of the Midwest Reliability Organization (MRO) Generator Testing Working Group. Prior to his 36-year career at NSP, David served for three years in the U. S. Peace Corps as a volunteer in the Rural Electrification Program in Ecuador. David received his Bachelor of Science in Electrical Engineering from the University of Kansas.
Ken Stenroos - Vice-chair General Manager	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, Florida	(561) 691-2545 ken.stenroos@ fpl.com	Ken Stenroos is the General Manager of Technical Services for Steam Turbine Generators and Electrical Equipment for NextEra Energy Power Generation's 40 GW fleet. In his 27 year career with NextEra, Ken has held positions of increasing responsibility throughout Power Generation, both in

	33408		the field and in the central organization. Ken holds a Bachelor of Science in Electrical Engineering from the University of Florida, and is a Licensed Professional Engineer. In addition to working on the NERC standards, Ken has also been an author and reviewer on several IEEE standards, and is a past member of the Synchronous Machinery Committee of the IEEE.
Bajarang (Baj) L. Agrawal Engineering Manager	Arizona Public Service Co. P. O. Box 53933 Phoenix, Arizona 85072-3933	(602)371-6386 bajarang.agrawal@aps.com	Dr. Baj L. Agrawal: Ph.D., University of Arizona, Tucson. Dr. Agrawal is Enginering Manager at Arizona Public Service Co., where he has worked since 1974. He has extensive experience in the analysis, control and testing of subsynchronous resonance, power system dynamics modeling and simulation, and field testing of generators. He has co-authored many papers on subsynchronous resonance analysis and power system testing and has co-authored a book on subsynchronous resonance. Dr. Agrawal is an IEEE fellow and is a registered professional engineer.
Donald G. Davies Chief Senior Engineer	Western Electricity Coordinating Council 155 North 400 West, Suite 200 Salt Lake City, Utah 84103	(801) 883-6844 donald@wecc.biz	Donald Davies is the Western Electricity Coordinating Council's (WECC's) chief senior engineer. He is WECC's power flow and dynamic stability modeling expert, Donald joined Western Systems Coordinating Council (WSCC) in 1983. The WSCC merged in April 2002 with the Western Regional Transmission Association (WRTA) and the Southwestern Regional Transmission Association (SWRTA) to form WECC. Donald has held positions of increasing responsibility in the areas of planning and technical support. For several years he was part of the WECC System Review Work Group and helped compile WECC's Study Program Annual Report, documenting the results of power flow and stability studies. Donald currently participates in WECC's Modeling and Validation Work Group and the Joint Synchronized Information Subcommittee. During 2004, Donald was recognized as a co-author of a paper titled "A New Thermal Governor Modeling Approach in the WECC" which received the IEEE Power Engineering Society's PES Prize Paper Award. He chaired the WECC task force that gathered data to improve the governor representation in simulation studies. Donald Davies received the Bachelor of Science and Master of Engineering degrees from Brigham Young University, Provo, UT, in 1978.
Les Hajagos Director/Senior Engineer	Kestrel Power Engineering Ltd 312 Bowling Green Court Mississauga, Ontario	(905)272-2191 les@ kestrelpower.com	Les M. Hajagos received his Bachelor of Applied Science in Electrical Engineering in 1985 and his Master's degree in 1987 both from the University of Toronto and is a registered Professional Engineer in the Province of Ontario. Since 1988 he has worked mainly in the analysis, design, testing and modeling

	L4Z2T1		and providing training courses on generators, turbines and power system control equipment and power system loads, first at Ontario Hydro, and since 2000 as one of the principals at Kestrel Power Engineering. He is an active member of the IEEE Power Engineering Society where he is chair of the Excitation System Performance and Modeling working group and past chair of the Generator Model Validation task force.
Gary Humphries Generator Excitation SME	Duke Energy Carolina P.O. Box 1244 Charlotte, North Carolina 28201	(704) 382-3363 gary.humphries@ duke-energy.com	After receiving an A.A.S.-ET degree from Central Piedmont Community College (Charlotte, NC), Gary began his 26 year career with Duke Energy in the Transmission Substation department. In 1991 Mr. Humphries moved to the Generation Department to perform commissioning, maintenance, and calibration activities on generator excitation controls equipment - AVRs and Static exciters. He also helped implement a system to document excitation system settings and the associated coordination of these systems with generator protection relays. Gary supported excitation systems on all Duke Generation facilitates including hydro/pumped storage, nuclear, fossil and CT/CC plants. Since 2002 Mr. Humphries has held the position of Generator Excitation System Subject Matter Expert (SME), being responsible for the technical review of procurement specifications, the engineering and technical support of commissioning and maintenance activities on excitation control equipment for Duke Energy's generation fleet. Beginning in 2004, Gary began providing technical guidance and training to engineering and operations staff on the requirements of SERC/NERC standards pertaining to generation facilities. Gary contributed to the development of Duke Energy's dynamic model validation program and was a co-recipient of the EPRI Technology Transfer award for their extensive use of the EPRI Power Plant Parameter Derivation (PPPD) software to comply with SERC regional criteria related to AVR/Exciter Dynamic model validations.
Venkat S. Kolluri Manager, Transmission Planning	Entergy Corporation 639 Loyola Avenue L-ENT-6K New Orleans, Louisiana 70113	(504) 576-4045 vkollur@ entergy.com	Sharma Kolluri (SM' 86) has a MSEE from West Virginia University, Morgantown and MBA from University of Dayton. He worked for AEP Service Corporation in Columbus, Ohio from 1977 through 1984 in the Bulk Transmission Planning Group. In 1984 he joined Entergy Services Inc, where he is currently the Manager of Transmission Planning. Sharma has over 30 years of experience in Planning and Operations area and is actively involved in several IEEE subcommittees, NERC Standards Development Task Forces and EPRI. His main areas of interest are power system planning and operations, voltage and dynamic stability and reactive power planning. Sharma was selected as IEEE Fellow in 2010 for making innovative contributions in the voltage stability area.

Gary Kruempel	MidAmerican Energy Co. 4299 NW Urbandale Drive P.O. Box 657 Des Moines, Iowa 50303	(515) 281-2510 gekruempel@ midamerican.com	Gary Kruempel is Compliance Director for the Energy Supply department of MidAmerican Energy Company. Gary has been at MidAmerican Energy Company for over 37 years. He began his career on the engineering team for a nuclear plant planned to be built in central Iowa. He then worked on the commissioning team for a coal fired generating plant. Following that he was a part of a generation engineer department first as an engineer, then senior engineer, and a manager for a number of years. While in generation engineering, the group was involved in the project management and commissioning of a combustion turbine peaking plant and a combined cycle plant. Gary then was a general manager responsible for the operational management of the MidAmerican gas-fired, oil-fired, wind generation as well as its LNG storage facilities. Gary received his Bachelor of Science degree in Engineering Science from Iowa State University and his Masters of Science in Electrical Engineering also from Iowa State University. After graduating from Iowa State, he served in the U.S. Navy nuclear submarine service for six years.
Daniel J. Leonard	GE Energy 1 River Road Building 53, Room 341 Schenectady, New York 12345-6000	(518) 385-0165 daniel1.leonard@ ge.com	Daniel J. Leonard received an A.A. in Engineering from Berkshire Community College, Pittsfield, MA in 1988. He received a B.S. and M.S. in Electrical and Computer Engineering from Clarkson University, Potsdam, NY in 1990 and 1992, respectively. In the summers of his undergraduate education Mr. Leonard worked at the Westinghouse Power Equipment Department in Greentree, PA and the New York Power Pool in Guilderland, NY. Mr. Leonard joined GE in 1991 where he is presently a Managing Director in the Energy Consulting organization. His work at GE has focused on power system dynamics, power plant test, simulation and analysis. Mr. Leonard is a registered professional engineer in the state of New York. He was recipient of the 1992 IEEE/PES T. Burke Hayes Student Prize Paper Award, and is a member of IEEE PES.
Jason MacDowell Manager – Thermal & Renewables	GE Energy Management 1 River Road B53-310A Schenectady, New York 12345	(518) 385 2416 jason.macdowell@ ge.com	Jason MacDowell is Principal Engineer and Manager of the Thermal and Renewable Power Projects segment of GE's Energy Consulting organization. He has an Electrical Engineering degree from Clarkson University ('99) and MBA from Union University ('13). He has expertise in interconnecting renewable generation into the bulk power system, renewable plant design, dynamic modeling, model validation and performance testing of thermal and renewable plants as well as power system protection. He has lectured and provided consultation regarding growth and interconnection of renewable energy systems to many governments, grid companies, generation owners and universities around America and Asia and Europe, and has contributed to the drafting of multiple grid codes and

			standards worldwide specifically addressing renewable generation. He spent over two years living and working in Beijing, China, providing consultation to Chinese policy makers, utilities, generation owners and design institutes to develop higher levels of wind energy penetration and to provide solutions for sub-synchronous resonance. Mr. MacDowell is an instructor of GE's PSEC protective relaying and renewable energy courses and of UVIG's Short Course on Interconnection and Performance of Variable Generation. He has authored or co-authored over 35 technical publications and standards, is a member of IEEE, of NERC Integration of Variable Generation Task Force (IVGTF) and a balloting member of NERC Generator Verification Standards Drafting Team (GVSDT). He also serves as the Chair of IEEE Std. 551-2006, "The Violet Book - Calculating Short Circuit Currents in Industrial and Commercial Power Systems."
Craig Quist Director Transmission Development & Planning	PacifiCorp 1407 W. North Temple Suite 275 Salt Lake City, Utah 84116	(801) 220-4264 craig.quist@ pacificorp.com	Craig Quist joined the PacifiCorp Transmission Planning department in February 2001. Because of his broad system planning background, he has been assigned to coordinate and evaluate wind farms that requested interconnection with the PacifiCorp transmission system. He has been directly involved with the analysis of many existing and proposed wind farms in Oregon, Wyoming, Idaho and Utah. Because of his demonstrated understanding of advanced power system modeling tools, he has evaluated every aspects of wind farm integration with transmission systems. In 2007, Craig was promoted to the position of Manager of Transmission Development & Planning at PacifiCorp and in 2012 was promoted to Director of Transmission Development & Planning – East Side at PacifiCorp. Previously, Craig held senior level transmission planning positions at Nevada Power Company and Western Electricity Coordinating Council - Technical Staff, and was the Lead Power Systems Analyst for Leeds & Northrup Systems. While at Nevada Power, he testified before the Nevada Public Utilities Commission concerning implementation of FERC's Order 888 and 889 rules. Additionally, Craig has testified before the FERC concerning wind generation integration issues and has made technical presentations at AWEA (American Wind Energy Association), UWIG (Utility Wind Integration Group) and American Super Conductor (AMSC) wind generation conferences. Craig received a BSEE degree from the University of Utah in 1973 and has completed graduate level power systems engineering courses from the University of Utah and University of Colorado, Boulder. Craig is a registered professional engineer in the both the states of Utah and Nevada, and is a member of the Institute of Electrical and Electronics Engineers (IEEE). He is currently a member of the

			WECC Technical Studies Subcommittee and is Chairman of the WECC Wind Generation Task Force.
Balbir S. Sandhu Generation Reliability Compliance Engineer	Manitoba Hydro 360 Portage Place (20) Winnipeg, Manitoba R3C 2P4	(204)360-3408 bssandhu@ hydro.mb.ca	Retired
William D Shultz Engineering Manager	Southern Company Generation 42 Inverness Center Parkway Mail Bin B425 Birmingham AL 35242	(205) 992-5526 wdshultz@ southernco.com	Bill Shultz is presently Engineering Manager, Electrical Services and Field Support, Technical Services of Southern Company Generation. He has 29 years of experience in Generating Plant Technical Services, including protective equipment application, start-up commissioning, and maintenance of protective relaying and control systems for electric power generating plants. His work experience includes the commissioning and maintenance of the control and protection of static excitation systems, variable speed drives, and emergency generation. He is active in Southern Company reliability standards compliance efforts as well as being involved in regional and national organizations responsible for utility reliability standards. He holds a BSEE from the University of Tennessee, a MSEE from Auburn University, and is a registered Professional Engineer in the State of Alabama.
Vladimir Stanisic Senior Engineer	BC Hydro Edmonds A02 6911 Southpoint Drive, Burnaby, BC, V3N 4X8	(604) 515-8793 vladimir.stanisic@ bchydro.com	Retired
Chifong Thomas Senior Director, Transmission and Strategy	BrightSource Energy, Inc. 1999 Harrison Street, Suite 2150 Oakland, California 94612	(510) 250-8166 cthomas@ brightsourceenergy.com	Chifong Thomas is the Senior Director, Transmission and Strategy at BrightSource Energy, Inc., where she manages transmission interconnections for the development of utility scale solar thermal power plants ranging from 200 MW to 1,000 MW. She has more than 40 years of electric utility experience, more than 37 of which in electric transmission planning for the Pacific Gas and Electric Company (PG&E) transmission system from 60 kV to 500 kV. She has both conducted and supervised transmission planning studies to develop plans for the PG&E transmission system. She has served as expert witness in various regulatory and judicial forums; and participated in developing planning methodologies, processes and criteria for PG&E and the Western Electricity Coordinating Council (WECC). She is the past secretary of the WECC Planning Coordination Committee and past chair of the WECC Technical Studies Subcommittee. She also served on the Technical Advisory Committee (Electrical Engineering) to the California Board of Registration for Professional Engineers and Land Surveyors. Ms Thomas holds a Bachelor of Science Degree in Electrical

			Engineering from Washington State University and is a registered Electrical Engineer in the State of California. She is also a senior member of the Institute of Electrical and Electronics Engineers (IEEE).
Edward J. Wingard Engineering, Projects and Field Services	American Electric Power 1 Riverside Plaza Columbus, Ohio 43215	(614) 716-1296 ejwingard@ aep.com	Ed Wingard holds a bachelor's degree in electrical engineering from Gannon University. Ed is responsible for the inspection, testing and maintenance recommendations, including design basis documents, of generators' motors and excitation systems throughout the AEP system. He also is responsible for the recommendation and implementation of all aspects of related system upgrade projects. Ed has more than 32 years of experience with American Electric Power and has previously worked for the General Electric Co. in their Small DC Motor and Generator Department. Ed has previously had responsibility at AEP for motors, batteries and battery monitoring systems, synchronous condensers, generator auxiliary systems and generator monitoring systems. He has extensive experience in developing and delivering technical training at AEP sites and also has delivered training for other utilities and at manufacturer's facilities. Ed has been involved with NERC Planning Standards and Compliance for more than 14 years.
David Youngblood Generation Planning Lead for Advocacy Support	Luminant Energy 500 N Akard St, Dallas Texas 75201	(903) 360-6601 David.youngblood @luminant.com	David has an Electrical Engineering degree from The University of Texas at Arlington, an MBA from The University of Texas at Tyler, and is a registered Professional Engineer in the State of Texas with more than 40 years of experience in the utility industry, working for Luminant and its predecessor companies. David's early career was concentrated in transmission system protection and involved transmission system studies, relay coordination, field support, and event analysis. For the last 30 years, David has served Luminant Power as an electrical SME and was the supervisor of field support and relay testing for generating facilities. These responsibilities include the management of plant and plant switchyard relay conceptual design, calculation of relay settings, responsible for all AVR, PSS and excitation system testing, analysis of relay operations and reporting, coordination of SPS review and installation, and providing comments for proposed NERC standards under development and ERCOT protocol revision requests. David currently serves as the Lead for Advocacy Support, dedicating his resources and extensive experience to working with Standards Development projects.
Stephen Crutchfield Standards Developer	North American Electric Reliability Corporation 3343 Peachtree Road, NE 4th Floor East Tower – Suite 400	609-651-9455 Stephen.crutchfield @nerc.net	Stephen Crutchfield is the NERC Staff Coordinator for Project 2007-09, Generator Verification. Stephen began his career with NERC in May 2007. Prior to joining NERC, Stephen was a Project Manager with Shaw Energy Delivery Services, managing engineering and construction projects in the substation and transmission line fields.

	Atlanta, GA 30326		Stephen's background also includes experience with PJM as Manager of RTO Integration, working on the operations and markets integration of new members (AEP, ComEd, Dayton, Dominion and Duquesne) into PJM and southern seams operations issues with Progress Energy, Duke and TVA. Stephen also helped lead the team that was developing GridSouth in the dual roles of Organization Architect and Manager of Customer Support. Prior to GridSouth, Stephen was the Manager of Power System Operations Training at Progress Energy where he spent over 10 years training System Operators and Engineers. Overall, Stephen was with Progress Energy for 16 years. Stephen received his Bachelor of Arts in Physics from the University of Virginia and Masters of Science in Electrical Engineering from North Carolina State University. Stephen holds a Master of Science in Management degree, also from North Carolina State University.